ALLEGHENY ENERGY CENTER PROJECT INSTALLATION PERMIT APPLICATION

ALLEGHENY ENERGY CENTER LLC

ALLEGHENY COUNTY, PA

MARCH 2019

Submitted by:

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Submitted to:

ALLEGHENY COUNTY ACHD HEALTH DEPARTMENT

Allegheny County Health Department
Air Quality Program
Engineering Section
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EXECUTIVE SUMMARY

Allegheny Energy Center LLC (AEC) retained ALL4 LLC (ALL4) to prepare this Allegheny County Health Department (ACHD) Application for an Installation Permit in accordance with ACHD's Article XXI §2102.04. Invenergy plans to construct the Allegheny Energy Center (AEC or Project), a nominal 639 megawatt (MW), natural gas-fired combined-cycle power plant. Emissions from this stationary source will trigger major source status under the Clean Air Act (CAA) New Source Review (NSR) and Title V Operating Permit (TVOP) programs. The Project will be located in Elizabeth Township, Allegheny County, Pennsylvania (Project Site). The Project will consist of a "one-on-one" (1 x 1), nominal 639 MW power plant that will include one combustion turbine (CT), one heat recovery steam generator (HRSG) with supplemental duct firing, and one steam turbine (ST). The proposed General Electric (GE) model (7HA.02) CT will fire clean low sulfur pipeline-quality natural gas. In addition to the CT and associated pieces of equipment, one auxiliary boiler, one dew point heater, one emergency generator, one fire water pump, and four above-ground storage tanks (AST) will be included as part of the Project. The Project will meet Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) requirements through the use of air pollution control technology, good operating practice, and reliance on natural gas and ultra-low sulfur diesel (ULSD) fuel.

Potential project-related emissions of sulfuric acid mist (H_2SO_4), carbon monoxide (CO), particulate matter (PM), PM less than 10 microns in diameter (PM_{10}), greenhouse gases (GHG), and nitrogen oxides (NO_X) [which is assessed as nitrogen dioxide (NO_2) for air quality modeling purposes] associated with the Project trigger the Prevention of Significant Deterioration (PSD) permitting requirements. Therefore, in addition to meeting BACT, air dispersion modeling that incorporated ACHD approved air quality modeling procedures was used to demonstrate that the Project will not result in any adverse air quality impacts for applicable PSD pollutants. The air quality modeling analyses of the Project demonstrate that it will not cause or contribute to any violation of the National Ambient Air Quality Standards (NAAQS) and will not cause any PSD increments to be exceeded.

Allegheny County is managed as a moderate nonattainment area for ozone (O_3) due to its inclusion in the Northeast Ozone Transport Region (OTR) and the entire county is classified as nonattainment for the 2012 annual particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) NAAQS. In addition, portions of Allegheny County, including Elizabeth Township where the AEC will be located, are designated as nonattainment for the 2010 1-hour sulfur dioxide (SO_2) NAAQS. With respect to ozone precursors, the Project is a major source for nitrogen oxides (NO_X) and volatile organic compounds (VOC). Therefore, NO_X and VOC will trigger major source Nonattainment New Source Review (NNSR) requirements as precursor emissions to O_3, and NO_X emissions will also trigger NNSR requirements as precursor emissions to $PM_{2.5}$. In addition to implementing LAER for all emissions sources of NO_X and VOC, emissions offsets will be obtained for the NO_X and VOC emissions, based on the Project's annual potential to emit. Project SO_2 and direct $PM_{2.5}$ emissions do not exceed the major NSR threshold and lead (Pb) emissions do not exceed the PSD significant emissions rate (SER), therefore, PSD is not triggered for Pb and NNSR is not triggered for SO_2 and $PM_{2.5}$. A summary of the Project emissions compared to the PSD and NNSR permitting thresholds is provided in Table ES-1.

The Project's emissions of air toxics exceed the *de minimis* levels established pursuant to ACHD's "Policy for Air Toxics Review of Installation Permit Applications." An air toxics modeling analysis was performed to evaluate carcinogenic and non-carcinogenic health risks of the Project. The results of this analysis show that the cumulative Maximum Individual Carcinogenic Risk (MICR) is less than 1×10^{-5} and the Hazard Quotient (HQ) and Cumulative Hazard Index (HI) were less than 1.0 and 2.0, respectively, and therefore no cumulative air toxics analysis is required, and the Project will not result in adverse health risks.

A complete review of air quality regulations that apply to the emissions units associated with the Project has been performed. These air quality regulations include regulations implemented and enforced by the United States Environmental Protection Agency (U.S. EPA) as well as regulations that the ACHD implements and enforces. The AEC will comply with those air quality regulations that apply to the proposed Project.

Finally, AEC has addressed the alternate siting analysis required pursuant to the NNSR regulations implemented by ACHD. This analysis demonstrates that the economic, social, and environmental benefits of the proposed Project outweigh adverse impacts associated with the location of the AEC in Allegheny County.

EXECUTIVE SUMMARY TABLE

Table ES-1
Summary of Project Emissions
Invenergy, LLC - Allegheny Energy Center

Pollutants	NO_X	CO	VOC	SO_2	PM	PM_{10}	$PM_{2.5}$	H_2SO_4	Pb	GHGs (CO_2e)	Total HAPs
Total Project Emissions	**145.71**	**170.41**	**93.40**	**24.43**	**45.62**	**90.71**	**90.66**	**22.29**	**9.24E-04**	**1,951,188.82**	**10.50**
NSR Major Source Threshold	100	100	100	100	100	100	100	100	100	100,000	10/25
Major Source?	Yes	Yes	No	No	No	No	No	No	No	Yes	No [a]
PSD Significant Net Emission Rate	40	100	N/A [c]	N/A [d]	25	15	N/A [d]	7	0.6	75,000	
Subject to PSD Review?	Yes [b]	Yes			Yes [e]	Yes [e]		Yes [e]	No	Yes	
Nonattainment Major Source Threshold	100		50	100			100				
Subject to Nonattainment New Source Review	Yes [f]		Yes	No			No				

[a] The AEC Facility and Project would be considered an area source for HAPs with respect to NESHAP because the PTE HAP emissions are less than 10 tons per year (tpy) for a single HAP and less than 25 tpy for total (combined)

[b] PSD applies for NO_X because NO_2 has a NAAQS and the Project is proposed in a NO_2 attainment area.

[c] PSD does not apply for VOC because the Project is proposed in the Northeast OTR which is managed as nonattainment area and VOC is a precursor pollutant of ozone.

[d] PSD does not apply for SO_2 or $PM_{2.5}$ because the Project is proposed in a $PM_{2.5}$ and SO_2 nonattainment area.

[e] Major source thresholds for NO_X and CO triggered therefore PSD significant net emissions rates applicable to NSR regulated pollutants subject to PSD.

[f] The Project is proposed in the Northeast OTR which is managed as a nonattainment area and NO_X is a precursor pollutant of ozone.

1. INTRODUCTION

AEC, a wholly-owned subsidiary of Invenergy LLC (Invenergy), is proposing to construct and operate the AEC, a nominal 639 MW, natural gas-fired combined-cycle power plant, to be located in Elizabeth Township in Allegheny County, Pennsylvania. The Project includes one combined-cycle power block in a "one-on-one" (1 x 1) configuration, consisting of a CT, a HRSG, a ST, and ancillary equipment. The CT proposed for the Project is a General Electric (GE) model 7HA.02. A supplemental duct burner (DB) will be installed in the HRSG. The CT and DB will exclusively fire pipeline-quality natural gas. Selective catalytic reduction (SCR) will be installed to minimize NO_X emissions and an oxidation catalyst will be installed to minimize CO and VOC emissions from the CT and DB.

This Installation Permit Application (Application) documents the emissions, air pollution control technology demonstrations, and applicable regulatory compliance demonstrations for the Project based on the installation of a GE 7HA.02 CT.

Ancillary equipment proposed as be part of the Project includes:

- One auxiliary boiler, natural gas-fired
- One dew point heater, natural gas-fired
- One emergency generator, ULSD-fired
- One fire water pump, ULSD-fired
- Two ULSD fuel, one lubricating oil, and one aqueous ammonia AST

The Project will be a major stationary source pursuant to the NSR air permitting program and the TVOP program that the ACHD enforces and implements. The Project will not be a major stationary source of hazardous air pollutants (HAPs). AEC has prepared this Application to address the Federal (U.S. EPA) and ACHD air quality regulations that are applicable to this Project.

1.1 APPLICANT INFORMATION

Invenergy is a privately-held company formed to develop, own, and operate power generation facilities in North America and Europe. To facilitate ACHD's review of this document, individuals familiar with both the Project and the preparation of this Application are identified below. ACHD should contact these individuals if additional information or clarification is required during the review process.

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1.2 STANDARDS FOR ISSUANCE OF AN INSTALLATION PERMIT

This Application was prepared in accordance with of the ACHD Rules and Regulations, Article XXI §2102.04(a) and (b). As listed in Table 1-1, §2102.04(b)(1)-(11) address the contents required for a complete Installation Permit application. This Application includes a demonstration that emissions related to the Project will not adversely affect compliance with the NAAQS pursuant to §2102.04(b)(4). The required control technology evaluations that are specified in

§§2102.06 and 2101.07 are presented in this Application. Finally, AEC has addressed the general requirements of §2102.05.

1.3 DOCUMENT ORGANIZATION

The balance of this document is divided into sections that address each component of a complete Application, as described below.

- Section 2 – Project Description provides a general description of the Project Site and the primary combined-cycle process by which power will be produced.
- Section 3 – Project Emissions presents a detailed review of the emissions during steady-state operations and startup/shutdown events from the CT and DB. Summaries of the methods used to quantify short-term and annual emissions rates are provided. This section also discusses Project emissions from auxiliary units, including emergency-use only equipment.
- Section 4 – Regulatory Analysis presents a discussion of applicable Federal and Allegheny County air quality regulatory programs. The focus of this section is to identify which regulations are directly applicable to the CT, DB, and the ancillary equipment.
- Section 5 – Control Technology Analysis documents how the NSR control technology evaluations were conducted for each emissions unit in accordance with §§2102.06 and 2102.07 and following U.S. EPA guidance. A BACT analysis was performed for those regulated NSR pollutants subject to PSD requirements, and a LAER analysis was performed for pollutants subject to nonattainment NSR requirements.
- Section 6 – Air Quality Modeling Evaluation outlines the technical approach utilized to conduct the Class I and II significant impact level (SIL), NAAQS, PSD increment, and air toxics evaluations and presents the results of the air quality modeling evaluation.
- Section 7 – Alternatives Analysis – provides an analysis of alternate project sites, sizes, production processes, and environmental control techniques for the Project to demonstrate that the benefits significantly outweigh the environmental and social costs imposed within Allegheny County as a result of the Project's location and construction.
- Section 8 – Allegheny County Health Department Installation Permit Application Forms and Supporting Information identifies the forms required for submittal of this Installation Permit application for ACHD.

SECTION 1 FIGURES AND TABLES

Table 1-1
Standards for Issuance of an Installation Permit

Regulatory Citation	Requirements	Application Compliance Determination
§2102.04(b)(1)	An identification of all other Installation Permits issued by the Department for the sources affected after November 15, 1990.	N/A – This Project is a new source.
§2102.04(b)(2)	The nature and amounts of emissions from the sources affected and from associated mobile sources.	The nature and amounts of emissions from each emissions unit are summarized in Section 3 and in Appendix C.
§2102.04(b)(3)	The location, design, construction and operation of the sources affected as they relate to emission characteristics.	The location and design of the emissions units are included in the Site Arrangement Plan (Figure 2-2). Refer to Appendix H for the Fugitive Dust Prevention and Control Plan related to construction activities. Refer to Section 3 and Appendix C for emissions characteristics as they relate to the operation of the emissions units.
§2102.04(b)(4)	Emissions from the proposed source will not prevent the attainment and maintenance of the ambient air quality standards established by Part A of this Article at any location within the Commonwealth, nor will such emissions interfere with reasonable further progress toward the attainment of the NAAQS; provided, however, that nothing herein contained shall preclude the applicant from agreeing to a more stringent emission limitation than established by this Article or securing enforceable emission reductions from existing sources so that such prevention or interference will not occur.	Section 6 summarizes the air quality modeling analysis which demonstrates that project emissions will not interfere with the attainment of the NAAQS nor the progress towards bringing the area into attainment with the NAAQS that are currently not in attainment.

Regulatory Citation	Requirements	Application Compliance Determination
§2102.04(b)(5)	The proposed source will comply with all applicable emission limitations established by this Article, or where no such limitations have been established by this Article, Reasonably Available Control Technology (RACT) has been applied to existing sources with respect to those pollutants regulated by this Article.	The Project emissions units are not subject to RACT requirements.
§2102.04(b)(6)	For new sources, BACT has been applied.	A BACT (or LAER as appropriate) analysis for each emissions unit is included in Section 5.
§2102.04(b)(7)	Emissions from the proposed source will not endanger the public health, safety or welfare.	An air quality modeling evaluation was conducted to compare concentrations resulting from the Project-related emissions to the NAAQS and carcinogenic and non-carcinogenic health risk concentration levels. The NAAQS and toxics modeling analyses and emissions inventory are included in Section 6 and Appendix F. The results demonstrate that the concentration levels due to the Project do not interfere with the attainment of the NAAQS nor the progress towards bring the area into attainment with the NAAQS that are currently not in attainment and the concentrations levels due to the Project are below the toxics risk thresholds for both carcinogenic and non-carcinogenic health effects.

Regulatory Citation	Requirements	Application Compliance Determination
§2102.04(b)(8)	The proposed source or modification will comply with all applicable New Source Performance Standards (NSPS) requirements, existing and new source Maximum Achievable Control Technology (MACT) standards, Generally Achievable Control Technology (GACT) standards, and National Emission Standards for Hazardous Air Pollutants (NESHAP), requirements established by the U.S. EPA, and where no applicable MACT emission limitations have been established by U.S. EPA after the federal deadline set for such establishment, such determinations of MACT as shall be made on a case-by-case basis by the Department.	The Project will meet the applicable requirements. The applicability evaluations and associated compliance demonstrations for the Project are identified in Section 4.
§2102.04(b)(9)	All existing air pollution sources within the Commonwealth which are required to have operating permits and which are owned, operated, or allowed to be operated, by the applicant or permittee or by any person controlling, controlled by, or under common control with the applicant or permittee are in compliance with all applicable requirements of the Air Pollution Control Act, the rules and regulations promulgated under the Air Pollution Control Act, this Article, any City of Philadelphia air pollution control rule or regulation, and any air pollution control plan approval, permit, or order of the Pennsylvania Department of Environmental Protection (PADEP), the Department, or the City of Philadelphia, as indicated by the PADEP's compliance docket, or such noncompliance is being corrected to the satisfaction of the primary air pollution control enforcement agency(s) for the source(s) in violation.	Current Invenergy power plants operated in the Commonwealth are in compliance with issued operating permits. Upon issuance of an operating permit Invenergy will operate AEC emissions units pursuant to the terms and conditions of the operating permit.

Regulatory Citation	Requirements	Application Compliance Determination
§§2102.04(b)(10)(A)-(B)	All terms and conditions for reasonably anticipated operating scenarios identified by the source in its application as approved by the Department. A. Shall require the source, contemporaneously with making a change from one operating scenario to another, to record in a log at the permitted source a record of the new scenario under which it is operating; and B. Must ensure that the terms and conditions of each such alternative scenario meet all applicable requirements under this Article.	An evaluation of potential steady-state operating scenarios for the CT and HRSG with DB is included in Section 3.1. Invenergy will operate the emissions units in accordance with the permitted scenarios presented in this Application.
§§2102.04(b)(11)	For new or reconstructed major sources of hazardous air pollutants or modifications of such sources, the proposed source or modification will comply with all applicable MACT standards, and where no applicable MACT emission limitation has been established by EPA, such determination of MACT as shall be made on either a case-by-case or source category basis by the Department under federal regulations promulgated pursuant to §112(g) of the Clean Air Act. A person appealing the establishment of a performance or emission standard by the Department under this Paragraph shall have the burden to demonstrate that the performance or emission standard does not meet the requirements of §112 of the Clean Air Act.	The Project is not a major source of HAP emissions. The evaluation of potentially applicable MACT standards is included in Section 4.3.3.

2. PROJECT DESCRIPTION

Invenergy proposes to construct, own, and operate a natural gas-fired combined-cycle power plant in Elizabeth Township in Allegheny County, Pennsylvania. Invenergy is a privately-held company formed to develop, own, and operate clean energy infrastructure. This section presents a description of the site and operations for the proposed Project.

2.1 SITE LOCATION AND ACCESS

The Project will be located on an approximate 15-acre site in the furthermost southeast point of Elizabeth Township, Allegheny County, Pennsylvania. The Project Site is south of Smithdale Road and the Youghiogheny River and north of the Westmoreland County line. The Project Site is situated in southwestern Pennsylvania, approximately 29 kilometers (km) southeast of Pittsburgh. A Facility Location Map is provided in Figure 2-1. The geographical coordinates for the approximate center of the Facility are:

- Universal Transverse Mercator (UTM) Easting: 602,441.60 meters (m)
- Universal Transverse Mercator (UTM) Northing: 4,453,386.84 m
- UTM Zone: 17
- North American Datum (NAD): 1983
- Longitude (degrees, minutes, seconds): 79°47' 45.40"W
- Latitude (degrees, minutes, seconds): 40°13' 28.74"N

The proposed Project Site is at a base elevation of approximately 309.4 m above mean sea level (amsl). The Project Site is situated approximately 400 m from the banks of the Youghiogheny River at its nearest point. A review of topographical features within a 5 km radius of the Project Site, using a United States Geological Survey (USGS) Quadrangle map and aerial imagery, indicates that the terrain elevations vary from approximately 225 m at the Youghiogheny River to the north at the lowest point, to approximately 385 m to the west at the highest point. The topography surrounding the proposed AEC is generally characterized as rolling terrain within the Pittsburgh Low Plateau.

The portion of Allegheny County where the Project will be located is classified as an attainment area, or unclassifiable, with respect to the NAAQS, except for $PM_{2.5}$, SO_2, and O_3. Allegheny County is managed as a moderate nonattainment area for O_3 for NSR permitting due to the Federal CAA requirements that include Pennsylvania in the Northeast OTR. Sections of Allegheny County including the Elizabeth Township are classified as nonattainment with the 2010 1-hr SO_2 NAAQS, and all of Allegheny County is designated as nonattainment for the 2015 annual $PM_{2.5}$ NAAQS. Sections of Allegheny County (The City of Clairton and Boroughs of Glassport, Liberty, Lincoln, and Port View) are also designated as nonattainment for the 1997 24-hour $PM_{2.5}$ NAAQS; however, the township of Elizabeth is not one of those sections within Allegheny County.

2.2 PROCESS DESCRIPTION

The Project includes one combined-cycle power block in a "one-on-one" (1 x 1) configuration, consisting of a CT, HRSG, ST, and ancillary equipment. The major components of the Project include:

- One natural gas-fired GE 7HA.02 CT and one HRSG (with supplementary fired DB) – equipped with SCR for NO_X control and an oxidation catalyst for CO and VOC control
- One auxiliary boiler, natural gas-fired
- One dew point heater, natural gas-fired
- One emergency generator, ULSD-fired
- One fire water pump, ULSD-fired
- Two ULSD fuel, one lubricating oil, and one aqueous ammonia AST

A site arrangement plan is presented in Figure 2-2. The Project components that produce air emissions in quantities subject to this Installation Permit Application (Application) are discussed below.

2.2.1 Combustion Turbine and Heat Recovery Steam Generator

The combined-cycle CT and HRSG with DB will incorporate an advanced GE model designed for high efficiency and performance. AEC obtained performance and emissions data from GE for the GE model 7HA.02 CT and HRSG with DB. This information was used to develop Project emissions rates and to conduct the required regulatory compliance demonstrations, control technology evaluations, and air quality modeling analyses for this Application. Detailed calculations with assumptions are provided throughout the Application and are also included within Appendix C.

In a combined-cycle process, ambient air is drawn into the compressor section of the CT through an inlet air filtration system. Inlet evaporative cooling may take place during periods of warm ambient temperatures and low relative humidity to further enhance the overall production capability of the CT. After the evaporative cooler section, air enters the compressor section where it is compressed and channeled to the fuel/mix combustion section of the CT.

The compressor section of the CT, commonly referred to as the gas generator section, generates emissions by means of the fuel combustion process. A transition duct within the CT directs the flow of hot gases from the gas generator to the power section of the turbine. Gas generator combustion gases expand through the stages of the power turbine where the thermodynamic energy is converted to mechanical power. This mechanical power is then transmitted through the rotation of the shaft to the generator of the CT, which is directly coupled to the power turbine. Finally, the generator takes this rotational power and converts it to electricity.

The hot combustion gases that are produced in the CT are directed into the HRSG through an exhaust transition duct where waste heat is captured and converted into steam energy before the exhaust gases exit the vertical stack. The HRSG duct contains the natural gas DB, which will be used at times to increase the temperature of the exhaust in the HRSG to enable the production of additional steam on an as-needed basis.

The steam produced in the HRSG is used in the ST to produce additional electrical power. Once mechanical work from the steam is captured, the steam is exhausted, and condensed in a vacuum within a condenser. The condensate is reused as feed water to the HRSG, creating a closed-loop system. The source of the cooling is through an Air Cooled Condenser (ACC) consisting of large fans flowing ambient air over steam distribution manifolds. The CT and HRSG with DB are the primary emissions units for the Project.

2.2.1.1 Proposed Combustion Turbine Exhaust Characteristics

The Project CT will be equipped with SCR using aqueous ammonia for the control of NO_X emissions. The CT will also be equipped with a dry-low NO_X (DLN) combustion system and the HRSG will be equipped with a low-NO_X burner (LNB). Emissions of NO_X from the CT and HRSG will be controlled to a level of 2.0 parts per million volume, dry (ppmvd) corrected to 15% oxygen (O_2) during steady-state operating loads, with or without duct firing. The emissions of unreacted ammonia, or ammonia slip, which result from the incomplete reactions with NO_X, will be minimized and limited to a concentration of 5.0 ppmvd corrected to 15% O_2. The amount of unreacted ammonia will be minimized through the use of an automatic ammonia injection metering system that evaluates the amount of unreacted ammonia along with the operational load of both the CT and the DB to determine the optimal amount of ammonia to inject ahead of the SCR catalyst.

The CT will also be equipped with an oxidation catalyst for control of VOC and CO emissions. The catalyst will control CO emissions from the CT and HRSG to a level of 2.0 ppmvd corrected to 15% O_2 during steady-state operating loads, with or without duct firing. VOC emissions will be controlled to a level of 1.5 ppmvd corrected to 15% O_2 during steady-state operating loads with duct firing and to a level of 1.0 ppmvd corrected to 15% O_2 during steady-state operating loads without duct firing. VOC emissions will be expressed as methane (CH_4).

The CT will fire pipeline quality natural gas. The use of low sulfur fuel will minimize the formation of SO_2, H_2SO_4, PM, PM_{10}, and $PM_{2.5}$. In addition, GHG emissions will be minimized through the use of the highly efficient GE 7H.02 combined cycle CT and HRSG unit.

A complete summary of the proposed CT and HRSG emissions limits for each regulated NSR pollutant at steady-state operation with and without duct firing and during startup and shutdown is provided in Table 2-1. These proposed emissions limits are based on the results of the BACT and LAER analyses as presented in Section 5.

2.2.1.2 Proposed Combustion Turbine Operation

The CT will be designed to operate up to 8,760 hours per year at 100% load firing natural gas. The DB is designed for the firing of natural gas and will typically be operated when the CT is at 100% load. The DB will be permitted to operate up to 8,760 hours per year, but will typically operate on an as-needed basis.

The energy consumption and production rates of the Project are summarized below:

- Gross Maximum Electrical Capacity (nominal) = 626 megawatt (MW) Total
- Maximum CT Heat Input (higher heat value [HHV]) = 3,844 million British thermal units per hour (MMBtu/hr)
- Maximum DB Heat Input (HHV) = 394 MMBtu/hr

Hourly electric generation values are dependent on various conditions, such as operating load, ambient temperature, and other variables discussed in Section 3.1. For the purposes of this Project, Invenergy analyzed the CT and HRSG with DB operating profiles under the ambient conditions of -26 degrees Fahrenheit (°F), 9°F, 53°F, 87.5°F, and 101.8°F. These temperatures, provided by GE, depict 50-year minimum, winter, spring/fall, summer, and 50-year maximum temperatures. The CT and HRSG will exhaust to atmosphere from a single stack.

2.2.2 **Ancillary Equipment**

A natural gas-fired auxiliary boiler, rated at 88.7 MMBtu/hr, will typically be used to provide high-temperature steam when the CT is offline in order to accommodate more rapid ST startups after extended shutdowns. Normally, the auxiliary boiler will not operate at full load once the CT has achieved steady-state operations.

A natural gas-fired dew point heater, rated at 3.0 MMBtu/hr, will operate as necessary to condition the natural gas prior to combustion to prevent condensation of the natural gas. Both the auxiliary boiler and dew point heater combustion gases will exhaust to atmosphere from individual dedicated stacks.

Other emissions units associated with the Project include an emergency generator and a fire water pump. The emergency generator, rated at 2,000 kilowatt-electric (kWe), will be used for emergency power in the event of a power outage. The fire water pump will be used for emergency purposes in the event of a fire or for routine maintenance and testing as required by the National Fire Prevention Association (NFPA) Code. The fire water pump engine is rated at a maximum of 282 brake horsepower (BHP). The emergency generator and fire water pump will only be operated during power interruptions to provide emergency power, lighting, and fire protection when the CT is not operating and at most once per week for less than 30 minutes for operational testing purposes. The BACT and LAER analyses addressing emissions limits for the emergency generator and fire water pump are provided in Section 5.6 and Section 5.7, respectively.

ULSD (i.e., 15 ppm by weight sulfur) fuel will be used in both the fire water pump and emergency generator engines. An approximate 3,500-gallon, dual walled, above ground, ULSD storage tank will be located in the base of the emergency generator. In addition, a 500-gallon, fire-rated, above ground, ULSD storage tank will be used for the fire water pump. A LAER analyses addressing emissions limits from the tanks is provided in Section 5.10.

A potential source of VOC emissions is the storage and use of turbine lubricating oil. The CT and the ST will include a lubricating oil sump with a system capacity of approximately 10,000 gallons. The CT and the ST will also be equipped with lubricating oil vents, which include electrostatic precipitators/demisters for lubricating oil mist control. As discussed in Section 3.2.3, use of low-volatility/low-VOC oil and low consumption rates of lubricating oil by the CT and ST will result in insignificant VOC emissions from these units.

Other storage tanks will be associated with the Project, however are not further described herein because the tanks will not contain liquids with the potential to emit VOC or HAPs. These non-VOC or HAP containing storage tanks are not addressed further in this Application.

The Project will use electrical circuit breakers insulated with sulfur hexafluoride (SF_6), a regulated GHG. The circuit breakers will be sealed units, equipped with low pressure alarms for leak detection and a low pressure lockout to minimize fugitive losses of SF_6. A BACT analysis addressing fugitive SF_6 emissions limits and providing further justification of the circuit breaker design and controls is provided in Section 5.8.

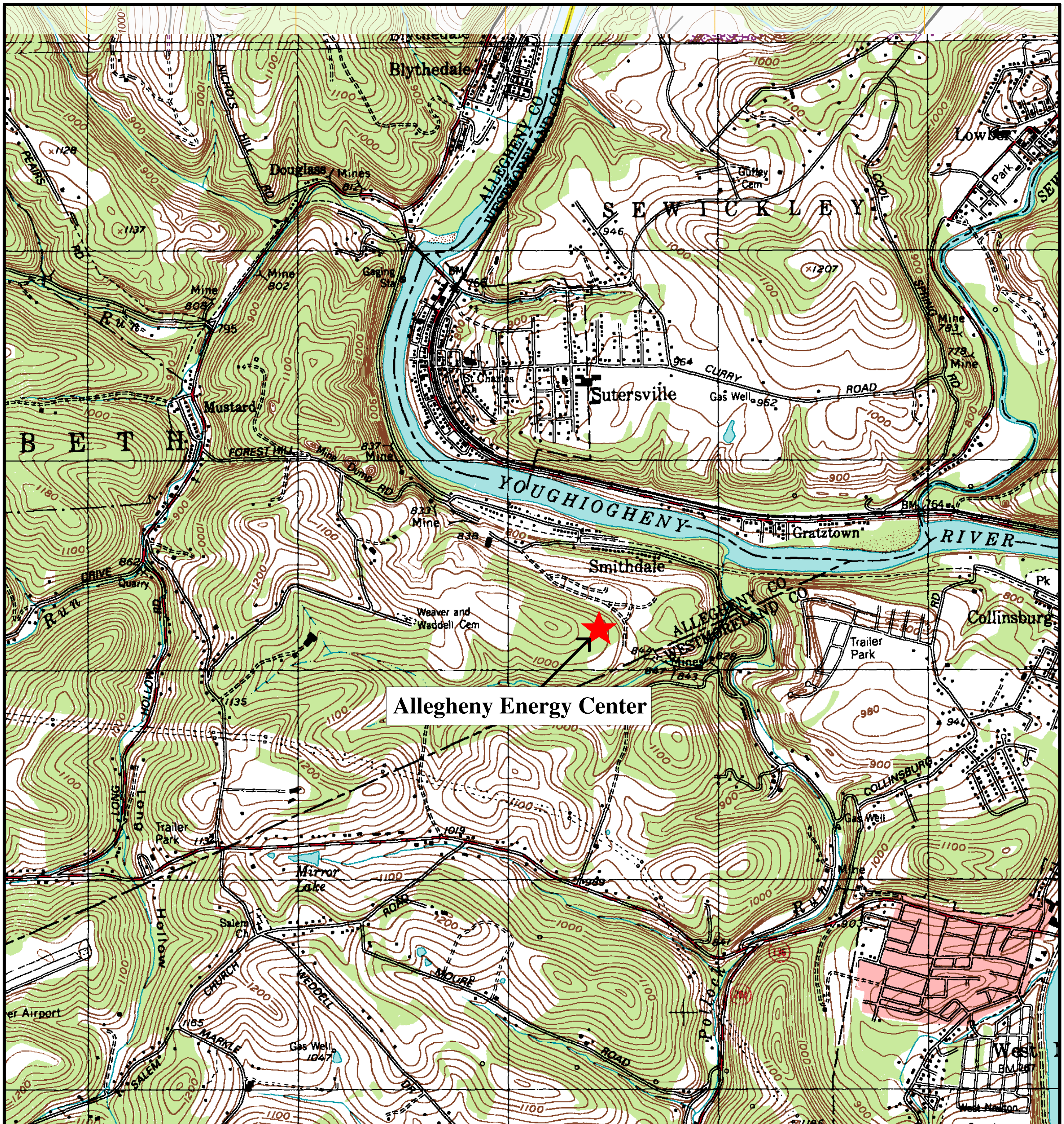
Fugitive GHG emissions due to potential leaks of natural gas from equipment such as piping, valves, flanges, and compressors, and from natural gas venting during pipe maintenance and startup/shutdown natural gas line purging have also been estimated for purposes of evaluating GHG emissions. The GHG BACT analysis in Section 5.9 addresses fugitive GHG emissions limits from natural gas piping.

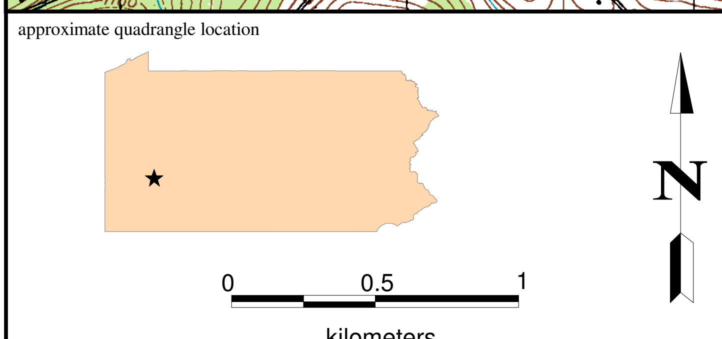
2.3 CONSTRUCTION ACTIVITIES

Construction of the Project is estimated to take approximately 30 months, beginning from issuance of an Installation Permit by ACHD. The construction activities during that period and approximate dates for each include the following:

- Power Generation Equipment delivery complete – 11/2021
- Site interconnection and electrical backfeed – 09/2022
- Fuel available – 10/2022
- Startup and commissioning begin – 02/2023
- Commercial operation – 06/2023

SECTION 2 TABLES AND FIGURES





Based on USGS 1:24,000 topographical map for McKeesport, PA 2013.

Allegheny Energy Center
Elizabeth Township, Allegheny County, PA

Figure 2-1
Facility Location Map

Figure 2-2
Site Arrangement Plan

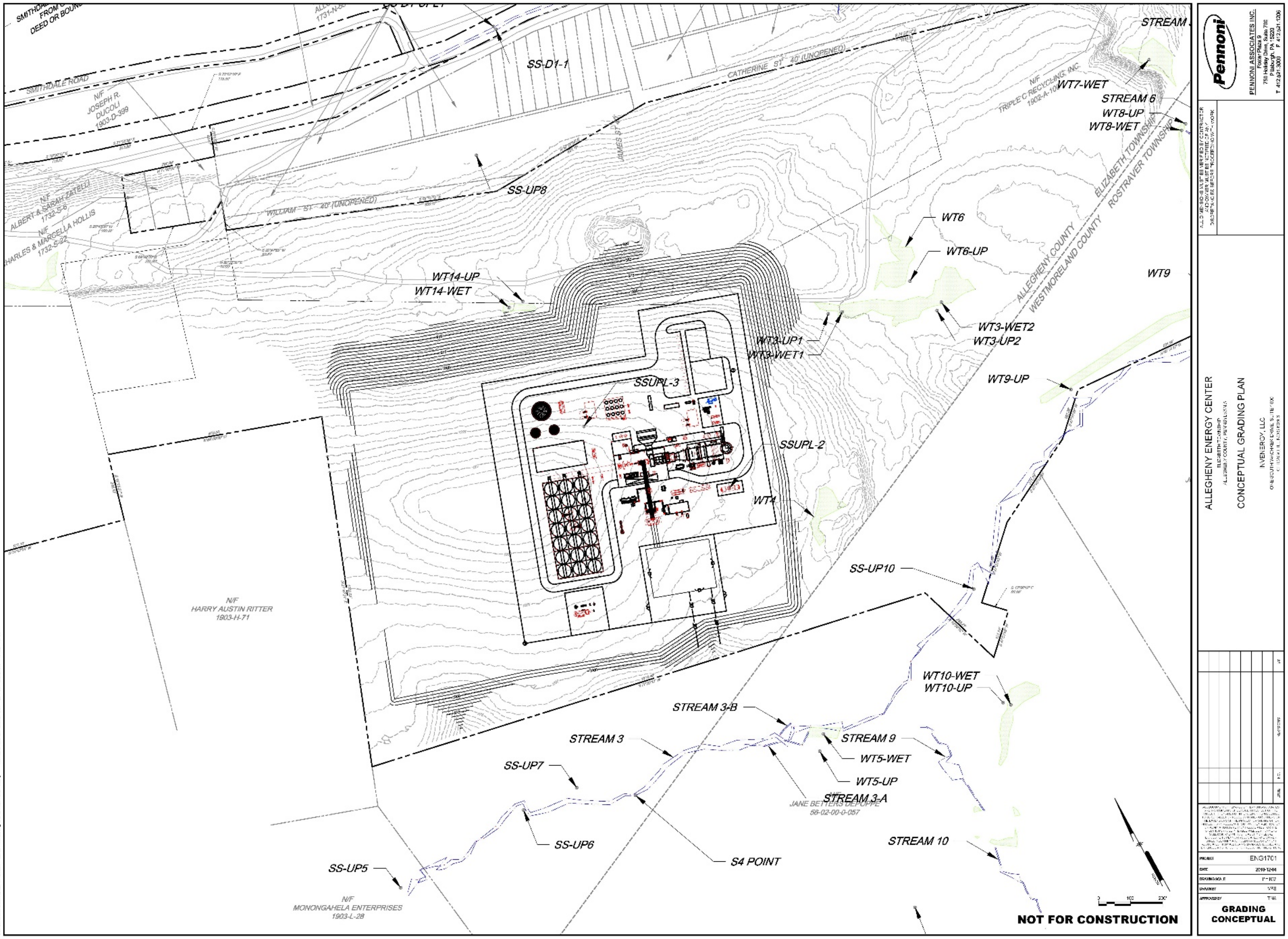


Table 2-1
Invenergy LLC - Allegheny Energy Center
Summary of Proposed Emissions Limits for CT and HRSG With and Without DB

Pollutant	Operation Mode/Unit[a]	Limit[c]	Units	Averaging Period	Basis
H_2SO_4	CT and HRSG with DB	0.00100	lb/MMBtu	Average of three test runs	BACT
	CT and HRSG without DB	0.00101	lb/MMBtu	Average of three test runs	
CO	CT and HRSG with and without DB	2.0	ppmvd @ 15% O_2	24-hour rolling	
	CT and HRSG with DB	18.8	lb/hr	3-hour rolling	
	CT and HRSG without DB	17.0	lb/hr	3-hour rolling	
NO_X	CT and HRSG with and without DB	2.0	ppmvd @ 15% O_2	24-hour rolling	LAER
	CT and HRSG with DB	30.9	lb/hr	3-hour rolling	
	CT and HRSG without DB	27.9	lb/hr	3-hour rolling	
VOC[b]	CT and HRSG with DB	1.5	ppmvd @ 15% O_2	Average of three test runs	
	CT and HRSG without DB	1.0	ppmvd @ 15% O_2	Average of three test runs	
	CT and HRSG with DB	8.1	lb/hr	Average of three test runs	
	CT and HRSG without DB	4.9	lb/hr	Average of three test runs	
$PM_{10}/PM_{2.5}$ (filterable and condensable)	CT and HRSG with DB	0.0058	lb/MMBtu	Average of three test runs	BACT
	CT and HRSG with DB	21.1	lb/hr	Average of three test runs	
	CT and HRSG without DB	0.0084	lb/MMBtu	Average of three test runs	
	CT and HRSG without DB	16.5	lb/hr	Average of three test runs	
PM filterable	CT and HRSG with DB	0.0029	lb/MMBtu	Average of three test runs	
	CT and HRSG with DB	10.6	lb/hr	Average of three test runs	
	CT and HRSG without DB	0.0042	lb/MMBtu	Average of three test runs	
	CT and HRSG without DB	8.2	lb/hr	Average of three test runs	
SO_2	CT and HRSG with DB	0.0014	lb/MMBtu	Average of three test runs	
	CT and HRSG without DB	0.0014	lb/MMBtu	Average of three test runs	
GHG	CT and HRSG with DB	6,468	Btu/kWh	Average of three test runs	
	CT and HRSG with DB	749	lb CO_2e/gross MWh	Average of three test runs	
CO	Cold Startup	900.0	lb/event	Not to exceed 55 minutes	
	Warm Startup	570.0	lb/event	Not to exceed 40 minutes	
	Hot Startup	390.0	lb/event	Not to exceed 20 minutes	
NO_X	Cold Startup	250.0	lb/event	Not to exceed 55 minutes	LAER
	Warm Startup	180.0	lb/event	Not to exceed 40 minutes	
	Hot Startup	90.0	lb/event	Not to exceed 20 minutes	
VOC	Cold Startup	280.0	lb/event	Not to exceed 55 minutes	
	Warm Startup	180.0	lb/event	Not to exceed 40 minutes	
	Hot Startup	90.0	lb/event	Not to exceed 20 minutes	

[a] Supplementary firing in HRSG using DB is typically only used at 100% CT load operating conditions.
[b] VOC is expressed in terms of a methane (CH_4) basis.
[c] Limits for $PM/PM_{2.5}/PM_{10}$ emissions rates are expressed in both lb/MMBtu and lb/hr. The lb/MMBtu emissions rates are inversely proportional to heat input, which varies with each operating case. Hence, the highest lb/hr emissions rate does not correspond with the highest lb/MMBtu emissions rate.

3. PROJECT EMISSIONS

This section presents a summary of proposed Project emissions and a discussion of the methodology used to calculate emissions, organized by emissions units. Within each emissions unit section, the methods used to calculate emissions are discussed, followed by a summary of the emissions estimates for the specific unit and, in the case of the CT, the mode of operation. Total Project annual potential emissions for regulated NSR pollutants and HAPs are summarized and used as the basis for classification of the Project with respect to applicable regulatory requirements evaluated in Section 4.

The Project consists of the following emissions units:

- One natural gas-fired GE 7HA.02 CT and one HRSG (with supplementary fired DB) – equipped with SCR for NO_X control and an oxidation catalyst for CO and VOC control
- One auxiliary boiler, natural gas-fired
- One dewpoint heater, natural gas-fired
- One emergency generator, ULSD-fired
- One fire water pump, ULSD-fired
- Two ULSD fuel, one lubricating oil, and one aqueous ammonia AST

The emissions calculation procedures used to quantify potential emissions from the Project are based on CT performance and emissions data provided by GE, additional equipment vendor data, water analysis data, emissions limitations specified in applicable NSPS and NESHAP, emissions factors documented in the U.S. EPA document "Compilation of Air Pollution Emission Factors, AP-42" (AP-42), and proposed BACT and LAER emissions limits. Proposed operating scenarios, including assumptions about the number and type of startups and shutdowns, are taken into account to develop emissions for the Project. Detailed emission calculations for each emissions unit are presented in Appendix C.

3.1 COMBUSTION TURBINE

The primary emissions units for the Project are the CT and HRSG with DB. The following subsections present the maximum hourly emissions during steady-state operations and startup/shutdown events, as well as the total annual emissions including startup/shutdown emissions.

3.1.1 **Steady State Operations**

Normal or steady-state operation of a CT is characterized as continuous operation at loads generally in the 40 to 100% range (over the range at which emissions compliance is achieved). The CT may be operated at base load (100% operating load for the current ambient conditions) up to 8,760 hours per year with and without duct firing. Heat input and emissions rates vary as a function of ambient temperature and relative humidity. Maximum heat input and maximum emissions rates typically occur at 100% load and the minimum design ambient temperature (i.e., -26 degrees ºF). Table 3-1 presents the maximum hourly emissions (lb/hr) for the CT with and without duct firing.

3.1.2 **Startup and Shutdown Operations**

For purposes of this Project, startup is identified as the period between the commencement of ignition and when the combined-cycle powerblock reaches CO and NO_X emissions compliance (i.e., 2.0 ppmvd CO @ 15% O_2 and 2.0 ppmvd NO_X @ 15% O_2), which is at approximately a 40% operating level. Table 3-2 presents the duration of startup and shutdown events in minutes and maximum emissions expressed in pounds per event. Data presented are based on information provided by GE for the 7HA.02 CT proposed for the Project. NO_X, VOC, and CO emissions vary during startup and shutdown events, other NSR pollutants do not vary during startup and shutdown events. Hot, warm, and cold starts are defined as follows:

- <u>Hot start</u> – a startup occurring within eight hours of the previous shutdown.
- <u>Warm start</u> – a startup occurring between eight hours and 72 hours after shutdown.

- Cold starts – a startup occurring 72 or more hours after a shutdown. Cold starts will be limited to 15 per year.
- Shutdown – defined as the period of time that the CT output is lowered with the intent to shutdown, beginning at the point at which the load drops below 40% until fuel flow ceases to the CT.

3.1.3 **Combustion Turbine Annual Emissions**

CT fuel firing rates and emission rates vary as a function of operating load, ambient temperature, relative humidity, and whether or not the DB is firing to supplement heat input to the HRSG. In addition, emissions rates of some pollutants (e.g., NO_X, CO, and VOC) are greatest during startups and/or shutdowns, while emissions of other NSR regulated pollutants are greatest during steady-state full load operation (e.g., SO_2). Accordingly, there is no single operating scenario that will result in a worst-case representation of annual or allowable emissions from the Project. Moreover, the use of the worst-case operating scenario for each pollutant does not represent realistic operating conditions and may grossly overestimate potential emissions, thereby adding additional regulatory complexity and expense.

To develop reasonable, yet conservative, estimates of potential emissions from the Project, nine potential operating scenarios were evaluated, encompassing the expected range of operation and number of startups and shutdowns. Steady-state 100% load conditions were evaluated to conservatively estimate emissions, although the CT will operate at reduced loads (i.e., 40-90%) depending on electricity demand. The nine operating scenarios evaluated are listed below, and detailed emissions calculations are included in Appendix C.

- Operating Scenario A – 8,760 hours of steady-state 100% load conditions without duct firing per rolling 12-month period
- Operating Scenario B – 8,760 hours of steady-state 100% load conditions with duct firing per rolling 12-month period
- Operating Scenario C – 4,380 hours of steady-state 100% load conditions with duct firing and 4,380 hours of steady state conditions without duct firing per rolling 12-month period
- Operating Scenario D – 6,985 hours of steady-state 100% load conditions with duct firing, plus a total of 220 startups and 220 shutdowns per rolling 12-month period

- Operating Scenario E – 7,015 hours of steady-state 100% load conditions without duct firing, plus a total of 220 startups and 220 shutdowns per rolling 12-month period
- Operating Scenario F – 7,615 hours of steady-state 100% load conditions with duct firing, plus a total of 265 startups and 265 shutdowns per rolling 12-month period
- Operating Scenario G – 7,615 hours of steady-state 100% load conditions without duct firing, plus a total of 265 startups and 265 shutdowns per rolling 12-month period
- Operating Scenario H – 8,200 hours of steady-state 100% load conditions with duct firing, plus a total of 365 startups and 365 shutdowns per rolling 12-month period
- Operating Scenario I – 8,200 hours of steady-state 100% load conditions without duct firing, plus a total of 365 startups and 365 shutdowns per rolling 12-month period

Within each scenario, different assumptions were made for the number/types of startups/shutdowns and hours of base load operation. The number of steady-state operating hours and the number of startups/shutdowns in each scenario were multiplied by the emissions rate for the representative CT operating mode. The steady state operating mode emissions were based on average annual ambient temperature conditions, unless otherwise noted. The maximum emissions from all operating scenarios for each configuration were calculated and have been proposed to establish annual emissions limits from the CT and the HRSG with DB. The results of these calculations are presented in Table 3-3. Based on the nine operating scenarios listed above, AEC proposes the following limits on CT and HRSG with DB operation:

- 8,760 hours of operation per rolling 12-month period for the CT
- 8,760 hours of operation per rolling 12-month period for the DB
- Total startup and shutdown events not to exceed 365 events per rolling 12-month period

Potential annual emissions of HAPs listed in Section 112(b) of the CAA from the CT and HRSG with DB are estimated using emissions factors from AP-42 and other sources as noted in Appendix C. Annual HAP emissions are calculated assuming the maximum hourly heat input for the CT for an operating scenario for the full 8,760 hours of maximum potential annual operation and multiplied by the HAP emissions factors without duct firing, plus the full 8,760 hours of maximum potential annual operations of the DB multiplied by the HAP emissions factors, as shown in

Appendix C. The total annual HAP emissions from the CT and HRSG with DB and the ancillary combustion equipment are presented in Table 3-4.

3.2 ANCILLARY EQUIPMENT

There are several emissions units that are part of the Project and support the operation of the CT. Descriptions of the emissions calculations for the ancillary equipment are provided in the following subsections.

3.2.1 **Natural Gas-Fired Auxiliary Boiler and Dew Point Heater**

The natural gas-fired auxiliary boiler will operate as needed to keep the HRSG warm during periods of turbine shutdown and provide sealing steam to the ST during warm and hot starts. The auxiliary boiler will have a maximum heat input capacity of 88.7 MMBtu/hr and will be limited to 337.9 million cubic feet (MMcf) of natural gas consumption per rolling 12-month period. Potential emissions are estimated based on vendor-supplied information, natural gas fuel specifications, and published AP-42 emissions factors.

The natural gas-fired dew point heater will operate as necessary to condition the natural gas prior to combustion to prevent condensation of the trace amounts of water that are present in natural gas. The maximum rated capacity of the dew point heater will be 3.0 MMBtu/hr, and it will have the potential to operate for 8,760 hours per year. Potential emissions are estimated based on vendor-supplied information, natural gas fuel specifications, and published AP-42 emissions factors.

Potential hourly and annual emissions for the auxiliary boiler are summarized in Table 3-5 and the dew point heater are summarized in Table 3-6. Annual potential total HAP emissions are summarized in Table 3-4 for both units, and detailed speciated HAP emissions are provided in Appendix C.

3.2.2 Emergency Ultra-Low Sulfur Diesel Engines

The Project will include a 2,000 kWe emergency generator and a 282 BHP fire water pump. The engines driving the emergency generator and fire pump will exclusively use ULSD fuel (15 ppm by weight sulfur) and will be operated during power interruptions to provide emergency power, lighting, and fire protection when the CT is not operating and at most once per week for less than 30 minutes for operational testing purposes. Operation of the emergency generator and fire water pump will each be limited to 100 hours per consecutive 12-month period for testing purposes. The fire water pump and the emergency generator will meet the emissions requirements specified in Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60, Subpart IIII). Emissions of regulated NSR pollutants from the emergency engines are based on either 40 CFR Part 60, Subpart IIII emissions limits, U.S. EPA Tier 2 emissions limits, U.S. EPA Tier 2 certified emissions data from representative manufacturers (MTU for the emergency generator and John Deere for the fire water pump), or AP-42 emissions factors for criteria pollutants and HAPs. Annual potential emissions based on these emissions factors for the emergency generator are shown in Table 3-7 and annual potential emissions for the fire water pump are shown in Table 3-8. Annual potential total HAPs emissions are shown in Table 3-4 for both units, and detailed speciated HAPs emissions are in Appendix C.

3.2.3 Storage Tanks

An approximate 3,500-gallon, dual walled, above ground, ULSD fuel storage tank will be located in the base of the emergency generator. In addition, a 500-gallon, fire-rated, above ground, ULSD fuel storage tank will be used for the fire water pump. The two ULSD fuel storage tanks are considered sources of VOC emissions. Another potential source of VOC emissions is the storage and use of turbine lubricating oil. The CT and the ST will include a lubricating oil sump with a system capacity of approximately 10,000 gallons. The CT and ST will also be equipped with lubricating oil vents, which include electrostatic precipitators/demisters for lubricating oil mist control. Use of low-volatility/low-VOC oil and a low consumption rate of lubricating oil in the CT and ST will result in insignificant VOC emissions [i.e., < 0.00001 tons per year (tpy)] from these sources. VOC emissions were determined for the tank storage operations using AP-42 Chapter 7.1. Annual potential VOC emissions from Project tanks are summarized in Table 3-9.

The proposed Project will also have a 20,000-gallon tank for storage of 19% aqueous ammonia (NH_3) for use in the SCR system. The tank will be located outdoors within an impermeable containment area that will be sized to accommodate the entire volume of one tank. The storage of aqueous ammonia does not result in NH_3 emissions.

3.3 GREENHOUSE GAS EMISSIONS FROM COMBUSTION UNITS

GHG emissions from Project combustion units were calculated as carbon dioxide (CO_2) equivalents (CO_2e). First, CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions were calculated and then the emissions were multiplied by their respective Global Warming Potentials (GWP) as listed in Table A-1 of 40 CFR Part 98 Subpart A (Mandatory Greenhouse Gas Reporting Rule). CO_2 emissions from the CT were based on CT manufacturer exhaust gas composition data. CO_2 emissions from the ancillary equipment, and CH_4 and N_2O emissions from the combustion units, including the CT and DB, were calculated using AP-42 emissions factors and 40 CFR Part 98 Subpart W emissions factors. CO_2e emissions for each combustion unit are summarized in Table 3-10.

3.4 FUGITIVE SF_6 GREENHOUSE GAS EMISSIONS FROM ELECTRICAL EQUIPMENT

Annual potential emissions of SF_6 from the circuit breakers are based on a maximum leakage rate of 0.5% per year as determined through BACT with a 15% safety margin. Based on the calculations for all circuit breakers, the maximum GHG emissions, as CO_2e, are calculated to be no more than 96.6 tons per year. Detailed calculations of GHG fugitive emissions from the circuit breakers are provided in Table 3-11.

3.5 FUGITIVE GREENHOUSE GAS EMISSIONS FROM NATURAL GAS PIPING

GHG emissions calculations for fugitive emissions from natural gas piping were based on emissions factors from Table W-1A of the Mandatory Greenhouse Gas Reporting Rules (40 CFR Part 98) for components in gas service for the Eastern U.S, as well as Table W-2 and W-7 for Leaker Emission Factors. The GWP factors used to calculate CO_2e emissions are based on Table A-1 of 40 CFR Part 98. The inventory of piping components was based on information from similarly sized facilities, and detailed emissions calculations are provided in Table 3-12. GHG emission calculations for releases of CH_4 related to piping maintenance and turbine startup/shutdowns were based on the assumptions and calculations detailed in Table 3-13 with regard to the numbers and types of piping component system purges per year and the volume of each piping system.

3.6 FUGITIVE EMISSIONS FROM ROADWAYS

Fugitive PM emissions may be generated by vehicular traffic on unpaved and paved roadways within the boundary of the Project. Fugitive PM emissions from roadways are anticipated to be negligible because once the Project construction is completed, all roadways will be paved. Traffic associated with the Project is limited to employee access, periodic deliveries of consumable materials, and visits by maintenance/repair vendors. Therefore, fugitive PM emissions were not calculated as part of the Project.

3.7 TOTAL PROJECT EMISSIONS

Table 3-14 summarizes total annual potential emissions from the Project including the CT and HRSG with DB and the ancillary equipment and compares the total emissions to the PSD and NNSR permitting thresholds. As discussed in Section 4, based on the total potential emissions, the proposed AEC will be considered a major stationary source with respect to emissions of NO_X, CO, VOC, PM, PM_{10}, H_2SO_4, and GHG. Thus, the Project will be subject to PSD review and will be subject to NNSR. Total HAPs emissions from the Project will not exceed 25 tpy and individual

HAP emissions will not exceed 10 tpy. Therefore, the AEC Facility and Project will **not** be a major stationary source of HAPs.

SECTION 3 TABLES

Table 3-1
Maximum Hourly Heat Input and Emissions During Steady-State Operations for CT and DB
Invenergy LLC - Allegheny Energy Center

Gross Maximum Electrical Capacity[a]	639 MW total	
Net Maximum Power	626 MW total	
Maximum CT Heat Input (HHV)	3,844 MMBtu/hr HHV	
Maximum DB Heat Input (HHV)	394 MMBtu/hr HHV	
Parameter	**Maximum Short Term Emissions Rates**[b]	
	CT w/o DB	**CT w/ DB**
NO_X ppmvd @ 15% O_2	2.0	2.0
NO_X lb/hr as NO_2	27.9	30.9
CO ppmvd @ 15% O_2	2.0	2.0
CO lb/hr	17.0	18.8
VOC ppmvd @ 15% O_2	1.0	1.5
VOC lb/hr as methane	4.9	8.1
CO_2 lb/hr	395,000.0	467,000.0
NH_3 Slip ppmvd @15% O_2	5.0	5.0
NH_3 Slip lb/hr	25.8	28.6
SO_X lb/hr as SO_2	5.1	5.6
SO_2 lb/MMBtu	0.0014	0.0014
$PM_{10}/PM_{2.5}$ lb/hr	16.5	21.1
$PM_{10}/PM_{2.5}$ lb/MMBtu	0.0084	0.0058
PM filterable lb/hr	8.2	10.6
PM filterable lb/MMBtu	0.0042	0.0029
H_2SO_4 lb/hr	3.6	4.0
H_2SO_4 lb/MMBtu	0.00101	0.00100
Pb lb/MMBtu	negligible	4.76E-07

[a] Nominal value.

[b] No emissions of fluoride (F), hydrogen sulfide (H_2S), or total reduced sulfur (TRS) are expected to occur.

Table 3-2

CT Startup/Shutdown Emissions

Invenergy LLC - Allegheny Energy Center

CT Startup/Shutdown Emissions Rates [(a)]				
Event	Duration	NO_X	CO	VOC
	Minutes	lb/event		
Cold Start	55	250.0	900.0	280.0
Warm Start	40	180.0	570.0	220.0
Hot Start	20	90.0	390.0	205.0
Shutdown	12	14.0	85.0	125.0

[(a)] Emissions of other regulated NSR pollutants are equivalent to steady state emissions during startup and shutdown.

Table 3-3
CT and DB Annual Emissions
Invenergy LLC - Allegheny Energy Center

Pollutant[(a)]	Operating Scenario Annual Emissions (tpy)									Maximum
	A	B	C	D	E	F	G	H	I	
NO_X	120.9	131.4	126.1	119.7	111.7	130.7	121.6	142.0	132.1	**142.0**
CO	73.6	80.2	76.9	124.5	119.5	138.6	132.9	161.7	155.6	**161.7**
VOC	21.0	34.5	27.8	64.7	54.1	74.3	62.6	92.5	79.9	**92.5**
PM	35.9	44.2	40.0	37.5	31.0	41.1	33.9	44.6	36.9	**44.6**
$PM_{10}/PM_{2.5}$	71.7	88.3	80.0	75.0	62.1	82.4	68.0	90.4	74.9	**90.4**
CO_2	1,633,740	1,922,820	1,778,280	1,635,893	1,411,038	1,795,302	1,543,999	1,970,428	1,699,817	**1,970,428**
SO_2	21.9	23.7	22.8	20.1	18.8	22.0	20.5	24.2	22.5	**24.2**

Operating Scenario A – 8,760 hours of steady-state conditions without duct firing per rolling 12-month period.
Operating Scenario B – 8,760 hours of steady-state conditions with duct firing per rolling 12-month period.
Operating Scenario C – 4,380 hours of steady-state conditions without duct firing and 4,380 hours of steady-state conditions with duct firing per rolling 12-month period.
Operating Scenario D – 6,985 hours of steady-state conditions with duct firing, plus 220 startups and shutdowns per rolling 12-month period (15 cold starts, 50 warm starts, 155 hot starts).
Operating Scenario E – 7,015 hours of steady-state conditions without duct firing, plus 220 startups and shutdowns per rolling 12-month period (15 cold starts, 50 warm starts, 155 hot starts).
Operating Scenario F – 7,615 hours of steady-state conditions with duct firing, plus 265 startups and shutdowns per rolling 12-month period (5 cold starts, 52 warm starts, 208 hot starts).
Operating Scenario G – 7,615 hours of steady-state conditions without duct firing, plus 265 startups and shutdowns per rolling 12-month period (5 cold starts, 52 warm starts, 208 hot starts).
Operating Scenario H – 8,200 hours of steady-state conditions with duct firing, plus 365 startups, and 365 shutdowns per rolling 12-month period.
Operating Scenario I – 8,200 hours of steady-state conditions without duct firing, plus 365 startups, and 365 shutdowns per rolling 12-month period.

(a) Emissions of H_2SO_4 and Pb are not included because they do not vary among operating scenarios.

(b) No emissions of F, TRS, or H_2S are expected.

Table 3-4

Annual HAP Emissions from Combustion Units

Invenergy LLC - Allegheny Energy Center

Emissions Unit	Annual HAPs Emissions (tpy)
CT	9.95
DB	0.50
Auxiliary Boiler	0.05
Dew Point Heater	3.81E-03
Emergency Generator	1.69E-03
Fire Water Pump	3.81E-04
Total HAPs	10.50

Table 3-5
Auxiliary Boiler Emissions
Invenergy LLC - Allegheny Energy Center

Parameter	Value
Fuel	Natural Gas
MMBtu/hr	88.7
Btu/CF	1,050
CF/hr natural gas	84,476
Max CF/yr natural gas	337,904,762
Max. hrs/yr	4,000
MMBtu/yr @ MCR	354,800
Stack temp., deg. F	270
Flue gas rate, ACFM	22,964
Flue gas rate, lb/hr	75,000
Stack height, ft.	50.0
Stack diameter, ft.	4.00
Stack exit velocity, ft/s	30.5

Pollutant	Emissions Factor	Emissions Factor Units	Emissions Factor Source	100% Load, lb/hr	TPY
NO_X	0.011	lb/MMBtu	Mfg. data	0.98	1.95
CO	0.04	lb/MMBtu	Mfg. data	3.62	7.24
VOC	0.004	lb/MMBtu	Mfg. data	0.35	0.71
PM	1.81E-03	lb/MMBtu	AP-42, Table 1.4-2 (7/98)[a]	0.16	0.32
PM_{10}	1.49E-03	lb/MMBtu	U.S. EPA's Emission Inventory and Analysis Group guidance 3/30/2012 with 3x safety factor[b]	0.1318	0.26
$PM_{2.5}$	1.23E-03	lb/MMBtu		0.1090	0.22
SO_2	1.10E-03	lb/MMBtu	(c)	0.10	0.20
H_2SO_4	1.35E-04	lb/MMBtu	(d)	0.01	0.02
Pb	5.00E-04	lb/MMSCF	AP-42, Table 1.4-2 (7/98)	4.2E-05	8.4E-05
NH_3	3.20	lb/MMSCF	(e)	0.27	0.54

(a) PM emissions factor represents the filterable portion only.
(b) PM_{10} and $PM_{2.5}$ emissions factors account for both the filterable and condensable portions of PM.
(c) SO_2 emissions factor calculated based on a 0.4 gr/100 scf sulfur content of natural gas.
(d) H_2SO_4 emissions factor conservatively calculated based on 10% molar conversion of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4.
(e) U.S. EPA Emission Inventory Improvement Program, "Estimating Ammonia Emissions from Anthropogenic Nonagricultural Sources - Draft Final Report", Table III-1, April 2004.

Table 3-6
Dew Point Heater Emissions
Invenergy LLC - Allegheny Energy Center

Parameter	Value
Fuel	Natural Gas
MMBtu/hr	3.0
Btu/CF	1,050
CF/hr natural gas	2,857
CF/yr natural gas	25,028,571
Max. hrs/yr	8,760
MMBtu/yr	26,280
Stack temp., deg. F	660
Flue gas rate, ACFM	2,208
Flue gas rate, lb/hr	4,700
Stack height, ft.	20
Stack diameter, ft.	1.50
Stack exit velocity, ft/s	20.82

Pollutant	Emissions Factor	Emissions Factor Units	Emissions Factor Source	100% Load, lb/hr	TPY
NO_X	0.011	lb/MMBtu	Mfg. data	0.03	0.14
CO	0.037	lb/MMBtu	Mfg. data	0.11	0.49
VOC	0.005	lb/MMBtu	Mfg. data	0.02	0.07
PM	4.80E-03	lb/MMBtu	Mfg. data[(a)]	0.01	0.06
PM_{10}	1.49E-03	lb/MMBtu	U.S. EPA's Emission Inventory and Analysis Group guidance 3/30/2012 with 3x safety factor[(b)]	0.0045	0.02
$PM_{2.5}$	1.23E-03	lb/MMBtu		0.0037	0.02
SO_2	1.10E-03	lb/MMBtu	(c)	3.30E-03	0.01
H_2SO_4	1.35E-04	lb/MMBtu	(d)	4.04E-04	1.77E-03
Pb	5.00E-04	lb/MMSCF	AP-42, Table 1.4-2 (7/98)	1.4E-06	6.26E-06
NH_3	3.20	lb/MMSCF	(e)	0.01	0.04

(a) PM emissions factor represents the filterable portion only.
(b) It is assumed that $PM_{10} = PM_{2.5}$. PM_{10} and $PM_{2.5}$ emissions factors account for both the filterable and condensable portions of PM.
(c) SO_2 emissions factor calculated based on a 0.4 gr/100 scf sulfur content of natural gas.
(d) H_2SO_4 emissions factor conservatively calculated based on 10% molar conversion of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4.
(e) U.S. EPA Emission Inventory Improvement Program, "Estimating Ammonia Emissions from Anthropogenic Nonagricultural Sources - Draft Final Report", Table III-1, April 2004.

Table 3-7
Emergency Generator Engine Emissions
Invenergy LLC - Allegheny Energy Center

Parameter	Value
Fuel	Ultra Low Sulfur Diesel
Fuel Btu/lb	19,170
Fuel density, lb/gal	7.39
Fuel Btu/gal	141,666
Number of units	1
Rating, KWe	2,000
Maximum power, KWm	2,280
BHP	3,058
Fuel consumption, gal/hr	147
MMBtu/hr[(a)]	20.87
Diesel sulfur content, wt. %	0.0015
Max. hrs/yr	100
Stack temp., deg. F	896
Exhaust rate, ACFM	16,103
Stack height, ft.	16
Stack diameter, ft.	1.5
Stack exit velocity, ft/s	151.87

Pollutant	Emissions Factor	Emissions Factor Units	Emissions Factor Source	100% Load, lb/hr	TPY
NO_X	4.56	g/bhp-hr	40 CFR §89.112, Table 2[(b)]	30.74	1.54
CO	2.61	g/bhp-hr	40 CFR §89.112, Table 2	17.60	0.88
VOC	0.24	g/bhp-hr	40 CFR §89.112, Table 2[(b)]	1.62	0.08
PM	0.15	g/bhp-hr	40 CFR §89.112, Table 2[(c)]	1.01	0.05
$PM_{10}/PM_{2.5}$	0.17	g/bhp-hr	(d)	1.17	0.06
SO_2	5.50E-03	g/bhp-hr	AP-42, Table 3.4-1	0.04	1.86E-03
H_2SO_4	6.74E-04	g/bhp-hr	(e)	0.0045	2.27E-04
NH_3	6.62	lb/1000 gal	(f)	0.99	4.93E-02
Pb	9.00E-06	lb/MMBtu	AP-42 Table 1.3-10	1.9E-04	9.39E-06

(a) Calculated from fuel consumption (gph x fuel heat content [MMBtu/gal]).

(b) Published emissions factor is for NO_X+NMHC. Invenergy assumed that NO_X emissions are 95% of this factor and VOC emissions are 5% based "*CARB Emission Factor for CI Diesel Engines - Percent HC in Relation to NMHC + NOX*" policy.

(c) It is assumed that the PM emissions factor reflects the filterable portion of PM only.

(d) It is assumed that PM_{10} = $PM_{2.5}$. PM_{10} and $PM_{2.5}$ emissions factors account for both the filterable and condensable portions of PM. The filterable portion of PM_{10} and $PM_{2.5}$ was obtained through vendor supplied information. The condensable portion of PM_{10} and $PM_{2.5}$ was obtained from AP-42 Chapter 3.4 Table 3.4-2 (10/96).

(e) H_2SO_4 emissions factor conservatively calculated based on 10% conversion of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4.

(f) EPA Emission Inventory Improvement Program, "Estimating Ammonia Emissions from Anthropogenic Nonagricultural Sources - Draft Final Report", April 2004.

Table 3-8

Fire Water Pump Engine Emissions

Invenergy LLC - Allegheny Energy Center

Parameter	Value
Fuel	Ultra Low Sulfur Diesel
Fuel Btu/lb	19,170
Fuel density, lb/gal	7.39
Fuel Btu/gal	141,666
Number of units	1
BHP	282
Fuel consumption, gph	13.7
MMBtu/hr[(a)]	1.9
Diesel sulfur content, wt. %	0.0015
Max. hrs/yr	100
Stack temp., deg. F	961
Exhaust rate, ACFM	1,400
Stack height, ft.	13
Stack diameter, ft.	0.50
Stack exit velocity, ft/s	118.8

Pollutant	Emissions Factor	Emissions Factor Units	Emissions Factor Source	100% Load, lb/hr	TPY
NO_X	2.85	g/hp-hr	40 CFR §60.4205(c), Table 4[(b)]	1.77	0.09
CO	2.60	g/hp-hr	40 CFR §60.4205(c), Table 4	1.62	0.08
VOC	0.15	g/hp-hr	40 CFR §60.4205(c), Table 4[(b)]	0.09	4.66E-03
PM	0.15	g/hp-hr	40 CFR §60.4205(c), Table 4[(c)]	0.09	4.66E-03
$PM_{10}/PM_{2.5}$	0.17	g/hp-hr	(d)	0.11	5.41E-03
SO_2	0.93	g/hp-hr	AP-42, Table 3.3-1	5.78E-01	2.89E-02
H_2SO_4	1.14E-01	g/hp-hr	(e)	7.08E-02	3.54E-03
NH_3	6.62	lb/1000 gal	(f)	9.18E-02	4.59E-03
Pb	9.00E-06	lb/MMBtu	AP-42 Table 1.3-10	1.75E-05	8.73E-07

(a) Calculated from fuel consumption (gph x fuel density [lb/gal] x fuel heat content [MMBtu/lb]).

(b) Published emissions factor is for NO_X+NMHC. Invenergy assumed that NO_X emissions are 95% of this factor and VOC emissions are 5% based "*CARB Emission Factor for CI Disel Engines - Percent HC in Relation to NMHC + NOX*" policy.

(c) It is assumed that the PM emissions factor reflects the filterable portion of PM only.

(d) It is assumed that $PM_{10} = PM_{2.5}$. PM_{10} and $PM_{2.5}$ emissions factors account for both the filterable and condensable portions of PM. The filterable portion of PM_{10} and $PM_{2.5}$ was obtained through vendor supplied information. The condensable portion of PM_{10} and $PM_{2.5}$ was obtained from AP-42 Chapter 3.4 Table 3.4-2 (10/96).

(e) H_2SO_4 emissions factor conservatively estimated based on 10% conversion of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4.

(f) EPA Emission Inventory Improvement Program, "Estimating Ammonia Emissions from Anthropogenic Nonagricultural Sources - Draft Final Report", April 2004.

Table 3-9
Storage Tank VOC Emissions
Invenergy LLC - Allegheny Energy Center

Description	Notes	Abbreviation	Units	Tank 1	Tank 2	Tank 3
General Tank Information						
Tank ID		-	-	ULSD Storage Tank	Lubricating Oil Tank	Fire Pump Engine ULSD Day Tank
Material		-	-	Distillate Fuel Oil No. 2	Residual Oil No. 6	Distillate Fuel Oil No. 2
Orientation		-	-	Vertical	Horizontal	Vertical
Vessel Shape		-	-	Cylindrical	Cylindrical	Cylindrical
Roof Type		-	-	Fixed	Fixed	Fixed
Tank Color		-	-	White	White	White
Roof Construction		-	-	Welded	Welded	Welded
Shell Construction		-	-	Welded	Welded	Welded
Product Days			Days	365	365	365
Capacity			Bbl	83	238	12
Capacity		-	Gal	3,500	10,000	500
Diameter		De [(p)]	ft	7.5	16.4	5.3
Height		He [(q)]	ft	13.00	6.28	3.14
Emission Factors for Fixed Roof Tanks (AP-42 Table 7.1, Organic Liquid Storage Tanks)						
Tank Radius		Rs	ft	3.75	8.21	2.65
Tank Roof Slope	(a)	Sr	ft/ft	0.06	0.06	0.06
Tank Roof Height		Hr	ft	0.23	0.51	0.17
Roof Outage		Hro	ft	0.08	0.17	0.06
Liquid Height		HL	ft	12.48	6.03	3.02
Tank Shell Height		Hs	ft	13.00	6.28	3.14
Vapor Space Outage		Hvo	ft	0.60	2.01	0.18
Tank Diameter		D	ft	7.50	16.43	5.29
Vapor Space Volume		Vv	ft^3	26.42	426.49	3.98
Paint Solar Absorptance For Fixed Roof Tanks	(b)	alpha	-	0.10	0.10	0.10
Daily Maximum Ambient Temperature	(c)	Tax	deg R	521.07	521.07	521.07
Daily Minimum Ambient Temperature	(c)	Tan	deg R	502.27	502.27	502.27
Daily Average Ambient Temperature	(c)	Taa	deg R	511.67	511.67	511.67
Liquid Bulk Temperature	(c)	Tb	deg R	511.27	511.27	511.27
Daily Total Solar Insolation Factor	(d)	I	BTU/ft^2	1,068.90	1,068.90	1,068.90
Daily Average Liquid Surface Temperature	(e)	TLa	deg R	512.29	512.29	512.29
Daily Maximum Liquid Surface Temperature	(f)	TLx	deg R	516.42	516.42	516.42
Constant in Vapor Pressure Equation	(g)	A	-	7.815	7.815	7.815
Constant in Vapor Pressure Equation	(g)	B	-	1800.03	1800.030	1800.030
Constant in Vapor Pressure Equation	(g)	C	-	246.89	246.89	246.89
Vapor Pressure at Daily Average Liquid Surface Temperature	(h)	Pva	psia	1.36E-01	1.36E-01	1.36E-01
Vapor Pressure at Daily Maximum Liquid Surface Temperature	(h)	Pva	psia	1.57E-01	1.57E-01	1.57E-01
Average Vapor Molecular Weight		Mv	lb/lb-mole	188	387	188
Ideal Gas Constant		R	psi*ft/mole*R	10.73	10.73	10.73
Vapor Density		Wv	lb/ft^3	4.66E-03	9.59E-03	4.66E-03
Atmospheric Pressure		Pa	psia	14.700	14.700	14.700
Breather Vent Vacuum Setting	(i)	Pbv	psig	-0.030	-0.03	-0.03
Breather Vent Pressure Setting	(i)	Pbp	psig	0.030	0.030	0.030
Breather Vent Pressure Setting Range		Pb	psig	0.060	0.060	0.060
Daily Ambient Temperature Range		Ta	deg R	18.80	18.80	18.80
Daily Vapor Temperature Range		Tv	deg R	16.53	16.53	16.53
Daily Vapor Pressure Range		Pv	psi	4.29E-06	4.29E-06	4.29E-06
Vapor Space Expansion Factor		Ke	-	0.028	0.028	0.028
Vented Vapor Saturation Factor		Ks	-	0.996	0.986	0.999
Vapor Molecular Weight		Mv	lb/lb-mole	188.00	387.00	188.00
Total Vapor Pressure of the Stored Liquid		Pva	psia	0.14	0.14	0.14
Annual Throughput Rate	(j)		gallons/yr	14,730	5,000	1,370
Annual Throughput Rate		Q	Bbl/Yr	351	119	33
Turnover Factor	(k)	Kn	-	1.00	1.00	1.00
Working Loss Product Factor	(l)	Kp	-	1.00	1.00	1.00
Standing Losses	(m)	Ls	lb/yr	1.26	41.42	0.19
Standing Losses		Ls	lb/hr	1.44E-04	4.73E-03	2.17E-05
Standing Losses		Ls	tpy	6.30E-04	0.02	9.51E-05
Working Losses	(n)	Lw	lb/yr	8.98	6.28	0.84
Working Losses		Lw	lb/hr	1.03E-03	7.17E-04	9.54E-05
Working Losses		Lw	tpy	4.49E-03	3.14E-03	4.18E-04
Total Tank Loss	(o)	Lt	lb/hr	1.17E-03	5.44E-03	1.17E-04
Total Tank Loss		Lt	tpy	5.12E-03	0.02	5.13E-04

[(a)] If unknown, use the value of 0.0625 ft/ft.

[(b)] AP-42 Chapter 7.1 Table 7.1-6 for aluminum paint color in good condition.

[(c)] Annual average, minimum and maximum temperatures are for Pittsburgh, PA obtained from https://www.usclimatedata.com/climate/pittsburgh/pennsylvania/united-states/uspa3601.

[(d)] Total solar insolation factor was obtained for Pittsburg, PA from the *Insolation Data Manual and Direct Normal Solar Radiation Data Manual* , as prepared by the Solar Radiation Resource Assessment, Solar Energy Research Institute (July 1990).

[(e)] Equation 1-26 ($0.44T_{AA}$+ $0.56T_B$+0.0079*α*I) on page 7.1-17 of AP-42 Chapter 7.1 was used.

[(f)] Figure 7.1-17 containing the equation ($T_{LX} = T_{LA} + 0.25*T_V$) on page 7.1-57 of AP-42 Chapter 7.1 was used.

[(g)] Each constant, A and B, was derived from the equation in Figure 7.1-15.

[(h)] Vapor pressures were calculated using antoine coefficients from *Elementary Principles of Chemical Processes: Third Edition.*

[(i)] If specific information on the settings for the breather vent pressure setting and vacuum setting was not readily available, therefore, 0.03 psig for P_{BP} and -0.03 psig for P_{BV} were assumed as typical values, pursuant to guidance provided in AP-42 Chapter 7.1.

[(j)] Throughput was estimated using plant provided information.

[(k)] When turnovers are less than or equal to 36, then K_N =1, pursuant to guidance provided in AP-42 Chapter 7.1.

[(l)] For all organic liquids except crude oils, K_P = 1, pursuant to guidance provided in AP-42 Chapter 7.1.

[(m)] Equation 1-2 ($365*V_V*W_V*K_E*K_S$) on page 7.1-10 of AP-42 Chapter 7.1 was used. Emissions are routed to a scrubber with 75% efficiency and have been adjusted accordingly.

[(n)] Equation 1-29 ($0.0010*M_V*P_{VA}*Q*K_N*K_P$) on page 7.1-18 of AP-42 Chapter 7.1 was used.

[(o)] Equation is: Ls + Lw (storage loss + working loss).

[(p)] Equation 1-14 on page 7.1-14 of AP-42 was used for horizontal tanks.

[(q)] Equation 1-13 on page 7.1-15 of AP-42 was used for horizontal tanks.

Table 3-10
GHG Emissions from Combustion Units
Invenergy LLC - Allegheny Energy Center

Unit Description	Fuel	Potential Annual Consumption	Fuel Consumption Units	Notes
Combustion Turbine w/o Duct Burner	Natural Gas	33,282,744	MMBtu	See Table C-4 in Appendix C, Max. of Operating Scenarios
Auxiliary Boiler	Natural Gas	354,800	MMBtu	
Dew Point Heater	Natural Gas	26,280	MMBtu	
Emergency Generator	ULSD	2,087	MMBtu	
Fire Water Pump	ULSD	194	MMBtu	

Unit Description	Fuel	CO_2 Emissions Factor	Emissions Factor Units	Emissions Factor Reference	PTE CO_2 TPY	PTE CO_2e[a] TPY
Combustion Turbine w/ Duct Burner	Natural Gas	115.8	lb/MMBtu	Mfg. data exh. comp.	1,927,334	1,927,334
Auxiliary Boiler	Natural Gas	107.4	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-1	19,057	19,057
Dew Point Heater	Natural Gas	107.4	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-1	1,412	1,412
Emergency Generator	ULSD	163.1	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-1	170	170
Fire Water Pump	ULSD	163.1	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-1	16	16

Unit Description	Fuel	CH_4 Emissions Factor	Emissions Factor Units	Emissions Factor Reference	PTE CH_4 TPY	PTE CO_2e[a] TPY
Combustion Turbine w/ Duct Burner	Natural Gas	2.20E-03	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2	37	917
Auxiliary Boiler	Natural Gas	2.20E-03	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2	0.39	10
Dew Point Heater	Natural Gas	2.20E-03	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2	0.03	0.7
Emergency Generator	ULSD	6.61E-03	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2	6.90E-03	0.2
Fire Water Pump	ULSD	6.61E-03	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2	6.42E-04	0.02

Unit Description	Fuel	N_2O Emissions Factor	Emissions Factor Units	Emissions Factor Reference	PTE N_2O TPY	PTE CO_2e[a] TPY
Combustion Turbine w/ Duct Burner	Natural Gas	2.20E-04	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2	4	1,093
Auxiliary Boiler	Natural Gas	2.20E-04	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2	0.04	12
Dew Point Heater	Natural Gas	2.20E-04	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2	0.00	0.9
Emergency Generator	ULSD	1.32E-03	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2	1.38E-03	0.4
Fire Water Pump	ULSD	1.32E-03	lb/MMBtu	40 CFR Part 98, Subpart C, Table C-2	1.28E-04	0.04

Unit Description	Fuel		PTE CO_2e[a] TPY
Combustion Turbine w/ Duct Burner	Natural Gas		1,929,344
Auxiliary Boiler	Natural Gas		19,079
Dew Point Heater	Natural Gas		1,413
Emergency Generator	ULSD		171
Fire Water Pump	ULSD		16
		Total (tpy) =	**1,950,023**

[a] CO_2e is carbon dioxide equivalent, calculated according to 40 CFR Part 98 Equation A-1:

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i$$

where GHGi = annual mass emissions of greenhouse gas i (metric tons/year)

GWPi = global warming potential of greenhouse gas i from 40 CFR Part 98 Table A-1 (below)

Pollutant	GWP
CO_2	1
CH_4	25
N_2O	298

Table 3-11
Fugitive SF_6 Emissions from Circuit Breakers
Invenergy LLC - Allegheny Energy Center

Input Data/Assumptions	138 kV	25 kV
Number of SF_6 Circuit Breakers	3	1
Circuit Breaker SF_6 Capacity, per breaker (lbs)	483.0	24.4
Total SF_6 circuit breaker capacity by size (lbs)	1,449.0	24.4
Total SF_6 capacity	1,473.4	lbs
Fugitive Loss/Leak Rate	0.5	percent per year[c]
SF_6 Global Warming Potential (40 CFR 98, Subpt. A, Table A-1)	22,800	CO_{2e}/SF_6
Potential Emissions - Fugitive SF_6[a]	8.5	lbs/year
Potential GHG - Fugitive SF_6 in CO_2e[b]	96.6	tons/year

[a] 1,473.4 total circuit breaker SF6 capacity x 0.5 percent per year leak rate x 1.15 margin = 8.5 lbs/year SF6.

[b] 8.5 lbs/year SF_6 x 22,800 CO_2e/SF_6 GWP / 2,000 lbs/ton = 96.6 tons/year CO_2e.

[c] Leak rate is based on the alarm threshold of 0.5%.

Table 3-12

Fugitive GHG Emissions from Natural Gas Piping

Invenergy LLC - Allegheny Energy Center

Area	Connections: Flange	Connections: Thread	Valves: Block	Valves: Control	Valves: Safety Relief	Other: Open Ended Line	Other: Compressor	Other: Ultrasonic Meter	Other: Orifice Meter	Notes
Primary Knock-out and Metering Yard	22	3	14	4	1	1	0	2	0	
Primary Filtration	44	10	40	4	2	2	0	0	0	Filtration prior to letdown station
Dew Point Heater	38	10	30	11	2	4	0	0	0	Natural Gas Fired
Fuel Gas Compressors/Bypass/Metering	42	16	18	8	4	4	3	0	3	3 x 50% Gas Compressors
Performance Heaters	10	0	2	0	1	1	0	0	0	Feedwater Based Heating
Fuel Gas Scrubbers	22	5	20	2	1	1	0	0	0	1 per CT
CT (inclusive of FG Module)	62	6	28	0	0	8	0	1	1	External to CT package
HRSG (Including BMS skid)	49	14	32	11	2	8	0	0	1	External to HRSG BMS
Auxiliary Boiler	38	10	30	11	2	4	0	0	0	
Subtotal	327	74	214	51	15	33	3	3	5	
Contingency	20%	20%	10%	10%	10%	10%	0%	0%	0%	
TOTAL	**392.0**	**89**	**235**	**56**	**17**	**36**	**3**	**3**	**5**	

Component	Count	Emissions Factor (scf/hr /comp.)[a]	CO_2 (tpy)[d]	CH_4 (tpy)[d]
Connectors	481	0.003	2.27E-04	0.26
Valves (block and control)	291	0.027	1.24E-03	1.39
Safety Relief Valves	17	0.04	1.07E-04	0.12
Open-ended Lines	36	0.061	3.46E-04	0.39
Compressors	3	13.3	6.29E-03	7.08
Meter[b]	3	2.93	1.39E-03	1.56
Orifice Meter[c]	5	0.212	-	0.19
Total			**9.60E-03**	**10.99**

Vol.% CO_2 in natural gas[d]: 0.032%

Vol.% CH_4 in natural gas[d]: 97.56%

GHG	Total Mass Emissions (tpy)	GWP[e]	CO_2e (tpy)
CO_2	9.60E-03	1	0.010
CH_4	10.989	25	274.72
Total CO_2e			274.73

(a) Whole gas emissions factors from 40 CFR Part 98, Subpart W, Table W-1A for components in gas service for Eastern U.S, unless otherwise stated.

(b) Meter emissions factor from 40 CFR Part 98, Subpart W, Table W-2 for Leaker Emission Factors—Non-Compressor Components, Gas Service.

(c) Whole gas emissions factors from 40 CFR Part 98, Subpart W, Table W-7 for Leaker Emission Factors—Transmission-Distribution Transfer Station Components, Gas Service. Emissions factor is for methane emissions.

(d) CO_2 and CH_4 fractions based on volume % CO_2 and CH_4 in natural gas.

(e) Global warming potentials (GWP) from 40 CFR Part 98, Subpart A, Table A-1.

Table 3-13

GHG Emissions from Natural Gas Piping Maintenance and Startup/Shutdown Line Purging

Invenergy LLC - Allegheny Energy Center

Process	Initial Conditions			Final Conditions			No. of Purges per Year	Annual Emissions[c]	
	Volume[a] (ft^3)	Press. (psig)	Temp. (F)	Press. (psig)	Temp. (F)	Volume[b] (ft^3)		CO_2 (TPY)	CH_4 (TPY)
Full piping system purge (650 psig piping)[a]	690	650	60	0	68	35,216	2	1.27E-03	1.43
Full piping system purge (100 psig piping)[a]	240	100	60	0	68	1,918	2	6.90E-05	0.08
CT/DB Skids Purges @ Startups/Shutdowns	74	650	60	0	68	3,782	365	2.48E-02	27.96
Auxiliary Boiler Skid Purges # Startups/Shutdowns	39	100	60	0	68	314	365	2.06E-03	2.32
Total								**0.03**	**31.79**

Vol.% CO_2 in natural gas[c]:	0.032%
Vol.% CH_4 in natural gas[c]:	97.56%

GHG	Total Mass Emissions (TPY)	GWP[d]	CO_2e (TPY)
CO_2	0.03	1	0.03
CH_4	31.79	25	794.8
Total CO_2e			794.8

Natural Gas Piping Inventory

Line Description	Size inches	Quantity ft	Pressure psig	Temp F	Volume cu.ft
Aux Boiler Area to Performance Heater Inlet Area	16	85	650	60	119
Fuel Gas Conditioning to Aux Boiler Area	16	210	650	60	293
Fuel Gas Conditioning to Regulating Skid	12	40	650	60	31
Metering Station to Fuel Gas Conditioning	12	40	650	60	31
Performance Heater Outlet Area to Filer Sep and CTG Inlet	4	220	650	60	19
Piping to Aux Boiler	10	50	650	60	27
Utility TP to Metering Station	16	120	650	60	167
CT Fuel Gas Skid	16	50	100	60	70
CT to Pilot	4	50	100	60	4
DB Runner	16	50	100	60	70
From Aux. Boiler Area to Aux. Burner Skid	12	50	100	60	39
From Aux. Boiler Area to Perf. Heater Area	6	250	100	60	49
From Perf. Htr. To DB Skid	4	85	100	60	7
Misc. 1"	1	350	650	60	2
					930
		Total piping @ 650 psig			690
		Total piping @ 100 psig			240

[a] Initial volume is calculated by multiplying the cross-sectional area by the length of pipe using the following formula: Vi = pi * [(diameter in inches/12)/2]^2 * length in feet = ft^3 using the table below.

[b] Final volume calculated using the compressibility factor modification of the ideal gas law to account for real gas behavior: $[(PV/ZT)_i = (PV/ZT)_f]$. $V_f = V_i (P_i/P_f) (T_f/T_i) (Z_f/Z_i)$, where the compressibility factor (Z) for natural gas is estimated based on Dranchuk and Abou-Kassem equation of state using http://checalc.com/solved/naturalgasZ.html:

For 500 psig natural gas at 60F, Z = 0.90

For 35 psig natural gas at 60F, Z = 0.99

For 0 psig natural gas at 68F, Z = 1

[c] CO_2 and CH_4 fractions based on volume % CO_2 and CH_4 in natural gas.

[d] Global warming potentials (GWP) from 40 CFR Part 98, Subpart A, Table A-1.

Table 3-14
Summary of Project Emissions
Invenergy, LLC - Allegheny Energy Center

Emissions Unit	NO_X	CO	VOC	SO_2	PM	PM_{10}	$PM_{2.5}$	H_2SO_4	Pb	GHGs (CO_2e)	Total HAPs
Combustion Turbine w/ Duct Burner	141.99	161.72	92.51	24.18	45.18	90.36	90.36	22.26	8.23E-04	1,929,344.06	10.45
Auxiliary Boiler	1.95	7.24	0.71	0.20	0.32	0.26	0.22	0.02	8.45E-05	19,078.86	0.05
Dew Point Heater	0.14	0.49	0.07	0.01	0.06	0.02	0.02	1.77E-03	6.26E-06	1,413.17	3.81E-03
Emergency Generator	1.54	0.88	0.08	1.86E-03	0.05	0.06	0.06	2.27E-04	9.39E-06	170.71	1.69E-03
Fire Pump	0.09	0.08	4.66E-03	0.03	4.66E-03	5.41E-03	5.41E-03	3.54E-03	8.73E-07	15.88	3.81E-04
Diesel and Lubricating Oil Tanks	-	-	0.03	-	-	-	-	-	-	-	-
Natural Gas Piping Fugitives	-	-	-	-	-	-	-	-	-	274.73	-
Natural Gas Maintenance + SU/SD Venting	-	-	-	-	-	-	-	-	-	794.82	-
SF_6 Circuit Breakers	-	-	-	-	-	-	-	-	-	96.58	-
Total Project Emissions	**145.71**	**170.41**	**93.40**	**24.43**	**45.62**	**90.71**	**90.66**	**22.29**	**9.24E-04**	**1,951,188.82**	**10.50**
NSR Major Source Threshold	100	100	100	100	100	100	100	100	100	100,000	10/25
Major Source?	Yes	Yes	No	No	No	No	No	No	No	Yes	No [a]
PSD Significant Net Emission Rate	40	100	N/A [c]	N/A [d]	25	15	N/A [d]	7	0.6	75,000	
Subject to PSD Review?	Yes [b]	Yes			Yes [e]	Yes [e]		Yes [e]	No	Yes	
Nonattainment Major Source Threshold	100		50	100			100				
Subject to Nonattainment New Source Review	Yes [f]		Yes	No			No				

[a] The AEC Facility and Project would be considered an area source for HAPs with respect to NESHAP because the PTE HAP emissions are less than 10 tons per year (tpy) for a single HAP and less than 25 tpy for total (combined)

[b] PSD applies for NO_X because NO_2 has a NAAQS and the Project is proposed in a NO_2 attainment area.

[c] PSD does not apply for VOC because the Project is proposed in the Northeast OTR which is managed as nonattainment area and VOC is a precursor pollutant of ozone.

[d] PSD does not apply for SO_2 or $PM_{2.5}$ because the Project is proposed in a $PM_{2.5}$ and SO_2 nonattainment area.

[e] Major source thresholds for NO_X and CO triggered therefore PSD significant net emissions rates applicable to NSR regulated pollutants subject to PSD.

[f] The Project is proposed in the Northeast OTR which is managed as a nonattainment area and NO_X is a precursor pollutant of ozone.

4. REGULATORY ANALYSIS

ACHD implements and enforces air quality rules at Article XXI Air Pollution Control Regulations. These air quality rules include regulations developed by ACHD and regulations incorporated by reference and based on PADEP and/or U.S. EPA regulations. In addition to the ACHD air quality rules there are a few air quality regulations that apply to the Project and are not part of ACHD's regulations. Invenergy reviewed Federal, PADEP, and Allegheny County air quality regulations to determine potentially applicable regulations for the Project. The regulations that potentially apply to the Project are identified and outlined in the following subsections. Applicability of Federal and PADEP air quality rules that are not part of ACHD air quality regulations are discussed in Section 4.2. Air quality regulations that ACHD implements and enforces either by delegated authority or its own authority are discussed in Section 4.3.

This Application includes the requisite forms included in Section 8, of the ACHD Air Quality Permit Application Forms that cite and provide detailed requirements of the applicable rules identified below. Additionally, the Method of Demonstrating Compliance Forms are included in Appendix A.

4.1 OVERVIEW OF AIR QUALITY REGULATIONS

ACHD implements and enforces air quality regulations for the purpose of protecting air quality. Most of these regulations have been approved by U.S. EPA pursuant to the CAA Section 110 State Implementation Plan (SIP) process. Air quality regulations related to the NSPS and NESHAPs have been delegated to ACHD for implementation and enforcement by U.S. EPA at 40 CFR Part 60 and 63 respectively. Finally, air quality regulations that are unrelated to the SIP or NSPS and NESHAPs are solely enforceable by ACHD.

4.2 U.S. EPA IMPLEMENTED AIR QUALITY REGULATIONS

The Federal regulations for which U.S. EPA has maintained implementation and enforcement responsibilities include the Compliance Assurance Monitoring provisions (40 CFR Part 64), the 40 CFR Part 61 NESHAPs, and Greenhouse Gas Reporting requirements (40 CFR Part 98). Thus, only these three regulations are evaluated as air quality regulations that are enforced at the Federal level. AEC reviewed these three air quality regulations for applicability to the Project in the subsections below.

4.2.1 **Compliance Assurance Monitoring**

CAM, promulgated as 40 CFR Part 64, requires facilities to prepare and submit monitoring plans (i.e., CAM Plans) for certain emissions units. The intent of a CAM Plan is to provide an on-going and reasonable assurance of compliance with emissions limits. Pursuant to the general applicability criteria, this regulation applies to units located at major stationary sources that use a control device to achieve compliance with an emissions limit and whose pre-controlled emissions levels exceed the major source thresholds under the TVOP program. The CAM rule also provides exemptions for emissions units subject to certain emissions limitations or standards, including NSPS and NESHAPs, Acid Rain Program (ARP) requirements, emissions trading programs, and where a facility's permit specifies a continuous compliance determination method. The Project will be a major stationary source (i.e., it will be required to obtain a 40 CFR Part 70 permit under ACHD air quality regulations); and therefore, CAM applicability must be addressed.

The Project will include the following control devices:

- SCR for control of NO_X emissions.
- Oxidation catalysts for the control of CO emissions.

AEC proposes to use continuous emissions monitoring systems (CEMS) to demonstrate compliance with the NO_X and CO emissions limits. As a result, the CAM regulations will not apply for demonstrating compliance with the Project emissions limits.

4.2.2 **40 CFR Part 61 NESHAPs**

The NESHAP originally required by the 1970 CAA, promulgated at 40 CFR Part 61, apply to specific compounds emitted from specific source categories. The Project is not a specific source category regulated by 40 CFR Part 61. Therefore, 40 CFR Part 61 requirements are not applicable to the Project.

4.2.3 **Mandatory Greenhouse Gas Reporting**

The Mandatory GHG Reporting requirements, promulgated at 40 CFR Part 98, were published by U.S. EPA on October 30, 2009 and require facilities that emit greater than 25,000 metric tons per year of carbon dioxide equivalent (CO_2e) to provide an annual reporting of GHG emissions. 40 CFR Part 98, Subpart D outlines the GHG monitoring and reporting requirements for Electricity Generation. Because the Project will emit more than 25,000 metric tons of CO_2e, GHG reporting will be required. The Project will prepare the necessary summary of annual GHG emissions and submit the summaries to U.S. EPA in compliance with the applicable provisions of 40 CFR Part 98.

4.3 ALLEGHENY COUNTY IMPLEMENTED HEALTH DEPARTMENT AIR QUALITY REGULATIONS

ACHD has developed air quality rules that regulate sources of air emissions. The air quality rules include regulations that are part of Federal and PADEP air quality programs and for which ACHD has been delegated authority to implement and enforce. In some instances, ACHD has directly incorporated by reference the Federal regulations. In other instances, ACHD has made slight modifications to existing Federal and PADEP air regulations. ACHD has also developed air quality rules that are not part of Federal or PADEP regulatory programs. An assessment of the applicability of the air quality regulations enforced by ACHD and to which the Project may be subject is provided in the following subsections.

4.3.1 New Source Review

The Project will be located in Allegheny County, Pennsylvania. The portion of Allegheny County where the Project will be located is classified as an attainment area, or unclassifiable, with respect to all of the NAAQS, except for $PM_{2.5}$, SO_2, and O_3. Allegheny County is managed as a moderate nonattainment area for O_3 for NSR permitting due to the Federal CAA requirements that include Pennsylvania in the Northeast OTR. Sections of Allegheny County including the Elizabeth Township are classified as nonattainment with the 2010 1-hr SO_2 NAAQS, and Allegheny County is designated as nonattainment for the 2012 annual $PM_{2.5}$ NAAQS. Sections of Allegheny County are also designated as nonattainment for the 1997 24-hour $PM_{2.5}$ NAAQS; however, the Elizabeth Township is not one of those sections.

In order to be subject to NNSR air permitting requirements, the Project emissions must be equal to the major source emissions nonattainment thresholds, which are 100 tpy for NO_X, SO_2, $PM_{2.5}$, and 50 tpy for VOC. Based on the emissions inventory developed for this Application, the Project is major for NNSR purposes for NO_X and VOC (precursor pollutants for O_3). The Project does not trigger NNSR for SO2 or $PM_{2.5}$ because the PTE is less than the NNSR emissions thresholds. The Project is major for PSD purposes for NO_X, CO, PM, PM_{10}, H_2SO_4, and GHG. Table 3-14 summarizes the NSR applicability for the Project.

ACHD incorporates by reference the Federal PSD regulations that are promulgated at 40 CFR Part 52.21. Similarly, ACHD incorporates the PADEP nonattainment NSR rules that are found at 25 PA Code Chapter 127, Subchapter E. However, ACHD has made minor administrative changes to the PADEP nonattainment NSR rules, which have been approved by PADEP and U.S. EPA.

AEC has demonstrated compliance with the NSR requirements as part of this Application. Specifically, AEC provided the necessary emissions summary documenting the basis for triggering NSR review (Section 3), conducted the necessary control technology evaluations (Section 5), and evaluated the impact that Project-related emissions have on ambient air concentration levels related to the NAAQS, PSD increments in the surrounding area, PSD increments at Class I areas, Air Quality Related Impacts (AQRVs) at Class I areas, and other impacts in the surrounding area (Section 6). AEC has also addressed the NNSR requirements related to siting of the project, compliance at other AEC sites within the Commonwealth of Pennsylvania, and the need to secure emissions reduction credits (ERCs) (Section 7).

4.3.2 Standards of Performance for New Stationary Sources

U.S. EPA has promulgated the Standards of Performance for New Stationary Sources, which implement emissions requirements for specific new, reconstructed, and modified sources, otherwise known as new source performance standards (NSPS), at 40 CFR Part 60. ACHD incorporates by reference the 40 CFR part 60 NSPS at Article XXI §2105.5. The following 40 CFR Part 60 NSPS Subparts are potentially applicable to the Project:

- 40 CFR Part 60, Subpart A – General Provisions
- 40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
- 40 CFR Part 60, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984
- 40 CFR Part 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
- 40 CFR Part 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
- 40 CFR Part 60, Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

Because the HRSG with the DB is subject to 40 CFR Part 60, Subpart KKKK, the Project is neither subject to 40 CFR Part 60, Subpart Da (Standards of Performance for Electric Utility Steam Generating Units) nor 40 CFR Part 60, Subpart GG (Standards of Performance for Stationary Gas Turbines).

ACHD incorporates by reference the Federal NSPS regulations. U.S. EPA has delegated ACHD the authority to implement and enforce the regulations found at 40 CFR Part 60.

4.3.2.1 40 CFR Part 60, Subpart A – General Provisions

The provisions of 40 CFR Part 60, Subpart A apply to the owner or operator of any stationary source subject to an NSPS. These general provisions include recordkeeping, reporting, monitoring, and testing requirements. Because the Project will be subject to a NSPS, it will be required to comply with the applicable requirements of 40 CFR Part 60, Subpart A.

AEC will comply with each of the applicable sections of the General Provisions as specified in 40 CFR Part 60, Subpart A. AEC has identified the key notification and submittal requirements of 40 CFR Part 60 Subpart A below:

- Provide notifications to ACHD and U.S. EPA Region 3 regarding the date construction is to be commenced and when actual start-up of the Project will occur per 40 CFR Part 60.7.

- Provide notifications to ACHD and U.S. EPA Region 3 regarding continuous monitoring systems (CMS) performance testing is demonstrated, which includes continuous opacity monitors (COMs) and continuous emissions monitors (CEMs) as appropriate per 40 CFR Part 60.7.

- Maintain the necessary records to document the operation and emissions of the Project so that the necessary excess emissions and CMS performance reports, as required to ACHD and U.S. EPA Region 3, can be submitted per 40 CFR Part 60.7.

- Conduct the necessary performance testing on the emissions units upon start-up of the emissions units subject to an NSPS and provide ACHD and U.S. EPA with notification of the performance testing per 40 CFR Part 60.9.

- Install and demonstrate operational readiness of required CMS prior to conducting the necessary performance tests per 40 CFR Part 60.9.

4.3.2.2 40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

The requirements of 40 CFR Part 60, Subpart Dc apply to each steam generating unit for which construction, modification, or reconstruction commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (i.e., 100 million British thermal units per hour, or MMBtu/hr) or less, but greater than or equal to 2.9 MW (i.e., 10 MMBtu/hr).

Because the proposed auxiliary boiler will meet the 40 CFR §60.41c definition of a steam generating unit and will have a maximum design heat input of 88.7 MMBtu/hr, which is less than 100 MMBtu/hr, but greater than 10 MMBtu/hr, the requirements of 40 CFR Part 60, Subpart Dc apply. However, since the auxiliary boiler will fire natural gas only, there are no applicable emissions standards under 40 CFR Part 60, Subpart Dc that will apply. AEC will comply with the appropriate 40 CFR Part 60, Subpart Dc notification and recordkeeping requirements for the auxiliary boiler in accordance with 40 CFR §60.48c(g)(2), by recording the amount of fuel combusted during each month.

The proposed dew point heater, which will have a maximum design heat input of 3.0 MMBtu/hr is not subject to Subpart Dc per 40 CFR §60.40c(e). The proposed CT and HRSG with DB are not subject to Subpart Dc per 40 CFR §60.40c(e) as the requirements of 40 CFR Part 60, Subpart KKKK apply to the proposed CT and HRSG with DB.

4.3.2.3 40 CFR Part 60, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984

The requirements of 40 CFR Part 60, Subpart Kb apply to each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification has commenced after July 23, 1984. Because the proposed petroleum liquid storage vessels associated with the Project have individual capacities less than 75 m^3 (i.e., 19,813 gallons) the storage vessels are not subject to the requirements of 40 CFR Part 60, Subpart Kb.

4.3.2.4 40 CFR Part 60, Subpart IIII – Standards of Performance For Stationary Compression Ignition Internal Combustion Engines

The requirements of 40 CFR Part 60, Subpart IIII apply to the owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence operation after July 11, 2005 and were manufactured after April 1, 2006 (for engines that are not fire water pump engines) and after July 1, 2006 (for fire water pump engines). 40 CFR Part 60, Subpart IIII will apply to the CI ICE that will drive the proposed 2,000 kW diesel-fired emergency generator and the proposed 282 BHP diesel-fired fire water pump.

Per 40 CFR §60.4205(b), the emissions standards applicable to the owners and operators of 2007 model year or later CI ICE with a displacement of less than 30 liters per cylinder driving an emergency generator are referenced in 40 CFR §60.4202. The 40 CFR §60.4202(a)(2) emissions standards for the CI ICE with a maximum engine power greater than or equal to 37 kilowatts (kW) state that the CI ICE must meet the certification emissions standards of 40 CFR §89.112 and the opacity limits of 40 CFR §89.113. These emissions standards and opacity limits for model year 2007 and later emergency engines with power ratings greater than 560 kW (751 BHP), which are referenced as Tier 2 emissions standards, and are listed below:

- 6.4 grams per kilowatt-hour (g/kW-hr) of non-methane hydrocarbons (NMHC) + NOx.
- 3.5 g/kW-hr of CO.
- 0.2 g/kW-hr of PM.
- 20% opacity during acceleration mode, 15% during lugging mode, and 50% during the peaks in either the acceleration or lugging modes.

The emissions standards applicable to the engine driving the proposed fire water pump are presented in 40 CFR §60.4205(c), where owners and operators of fire water pump engines with a displacement of less than 30 liters per cylinder must comply with the emissions standards presented in 40 CFR Part 60, Subpart IIII, Table 4. For a fire water pump of 2009 model year or later with a power rating greater than or equal to 130 kW (i.e., 175 BHP) but less than 225 kW (i.e., 300 BHP), the following emissions standards apply:

- 4.0 g/kW-hr of NMHC + NOx
- 3.5 g/kW-hr of CO
- 0.20 g/kW-hr of PM

Since October 1, 2010, 40 CFR §60.4207(b) requires that engines use compliant fuel in accordance with 40 CFR §80.510(b). Such fuel must have a maximum sulfur content of 15 parts per million (ppm) and have either a minimum cetane index of 40 or a maximum aromatic content of 35% by volume.

The fire pump CI ICE that will be part of the Project will be newly purchased from the ICE manufacturer which means that compliance with the emissions limit of 40 CFR Part 60, Subpart IIII are initially certified by the manufacturer. Subsequently, AEC will demonstrate compliance with the emissions limits and requirements of 40 CFR Part 60, Subpart IIII by following the manufacturer's written instructions for operation of the CI ICE. AEC will only change those emission-related settings that are permitted to be changed based on the manufacturer's guidance. Additionally, AEC will only use ULSD to fire the fire water pump.

4.3.2.5 40 CFR Part 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

40 CFR Part 60, Subpart KKKK applies to owners or operators of a stationary CT with a heat input at peak load equal to or greater than 10 MMBtu/hr based on the higher heating value (HHV) and that commenced construction, modification, or reconstruction after February 18, 2005. Only the heat input rate to the CT is considered when determining 40 CFR Part 60, Subpart KKKK applicability. Because the construction of the CT will commence after February 18, 2005, and the CT will have a heat input at peak load equal to or greater than 10 MMBtu/hr based on the HHV of natural gas, 40 CFR Part 60, Subpart KKKK requirements will apply to the proposed stationary CT and HRSG with DB.

The CT will fire only clean, low sulfur, pipeline quality natural gas. Emissions standards for NO_X and SO_2 will apply when the CT is operating with or without the HRSG with DB. The proposed CT must comply with the following emissions standards for a new turbine firing natural gas with a heat input at peak load of greater than 850 MMBtu/hr:

- 40 CFR §60.4320(a) and Table 1 – NO_X
  - 15 ppm at 15% oxygen (O_2), or
  - 0.43 pounds per megawatt hour (lb/MWh) of useful output

- 40 CFR §60.4330(a)(1) and (2) – SO_2
  - 0.90 lb/MWh gross output, and
  - 0.060 pounds per million British thermal units (lb/MMBtu) heat input

The HRSG and DB will not operate independently of the CT. Therefore, the NO_X emissions standards associated with heat recovery units operating independent of the CT do not apply.

AEC will demonstrate compliance with 40 CFR Part 60, Subpart KKKK requirements via several methods. For NO_X emissions limits, AEC will operate the emissions control(s) that are determined to be LAER/BACT. A NO_X CEM will be used to monitor hourly NO_X emissions and additional CMS data will be collected to demonstrate compliance with the NO_X emissions standards. The use of natural gas to fire the CT will ensure that the SO_2 emissions standard is met and AEC will use natural gas supplier data to document the sulfur content of the fuel. AEC will conduct the necessary initial and subsequent NO_X performance tests and submit the necessary reports required per 40 CFR Part 60, Subpart KKKK. It should be noted that the proposed NO_X and SO_2 emissions limits for the CT are less than the emissions limits specified at 40 CFR Part 60, Subpart KKKK.

4.3.2.6 40 CFR Part 60, Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

40 CFR Part 60, Subpart TTTT applies, with certain exceptions, to owners or operators of any steam generating unit, integrated gasification combined cycle (IGCC), or stationary CT that commenced construction after January 8, 2014 or commenced modification or reconstruction after June 18, 2014 and that have a base load rating greater than 250 MMBtu/hr and serves a generator capable of selling greater than 25 MW of electricity to a utility power distribution system. Pursuant to §60.5520(a), AEC must meet the applicable emissions standards in Table 2 of 40 CFR Part 60, Subpart TTTT. Because the CT combusts only natural gas and will be selling its electric output, one of the two following emissions standards will apply:

- When the CT supplies more than its design efficiency or 50%, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis, either of the following standards must be met:
    - 1,000 lb CO_2/MWh of gross energy output, or
    - 1,030 lb CO_2/MWh of net energy output

AEC is required to comply with the gross energy output emissions standard unless a petition is submitted to ACHD and U.S. EPA approving the net energy output emissions standard as an alternative emissions standard.

The provisional certification of the CMS or 180 days after the CT commences commercial operation, whichever is earlier, will trigger the requirement for AEC to begin tracking emissions information at the start of the month following the month when the triggering event occurred. AEC will monitor gross or net energy output and fuel usage so that a 12-month rolling average of information related to compliance with the emissions standard can be calculated and compliance can be demonstrated. AEC will prepare the necessary reports and maintain the necessary records required by 40 CFR Part 60 Subpart TTTT.

4.3.3 National Emission Standards for Hazardous Air Pollutants

Pursuant to the CAA Amendments (CAAA) of 1990, NESHAP regulations were further promulgated in 40 CFR Part 63, which implement MACT emissions limits. 40 CFR Part 63 applies to specific source categories that are considered either major or non-major (i.e., area) sources of HAPs. A major source of HAPs is defined as a stationary source that emits or has the PTE 10 tons per year (tpy) or more of any single HAP, or 25 tpy or more of any combination of HAPs. Emissions from the Project do not exceed the 10 tpy threshold for any single HAP, or the 25 tpy threshold for any combination of HAPs. Therefore, the Project is considered an area source of HAPs. As an area source of HAPs, the emissions standards of 40 CFR Part 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines and 40 CFR Part 63, Subpart DDDDD – NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters will not apply because these rules regulate major sources of HAPs. The Project is potentially subject to the following 40 CFR Part 63 Subparts:

- <u>40 CFR Part 63, Subpart A</u> – General Provisions
- <u>40 CFR Part 63, Subpart ZZZZ</u> – NESHAP for Stationary Reciprocating Internal Combustion Engines
- <u>40 CFR Part 63, Subpart JJJJJJ</u> – NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources

4.3.3.1 40 CFR Part 63, Subpart A – General Provisions

The provisions of 40 CFR Part 63, Subpart A apply to the owner or operator of any stationary source subject to a NESHAP. Because the Project is subject to 40 CFR Part 63 Subparts, the requirements of Subpart A will apply. AEC will comply with each of the applicable sections of the General Provisions as specified in 40 CFR Part 63, Subpart A.

4.3.3.2 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The provisions of 40 CFR Part 63, Subpart ZZZZ apply to the engines driving the emergency generator and fire water pump. In accordance with 40 CFR §63.6590(c)(1), a new stationary reciprocating internal combustion engine (RICE) located at an area source of HAPs must demonstrate compliance with 40 CFR Part 63, Subpart ZZZZ by operating in compliance with the requirements of 40 CFR Part 60, Subpart IIII or Subpart JJJJ. Because the engines driving the emergency generator and the fire water pump are CI RICE, demonstrating compliance with the requirements of 40 CFR Part 60, Subpart IIII ensures that the requirements of 40 CFR Part 63, Subpart ZZZZ are met. Section 4.3.2.4 provides a summary of AEC's strategy for being in compliance with 40 CFR Part 60, Subpart IIII.

4.3.3.3 40 CFR Part 63, Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

The provisions of 40 CFR Part 63, Subpart JJJJJJ apply to owners or operators of industrial, commercial, or institutional boilers located at an area source of HAPs. However, while the auxiliary boiler meets the 40 CFR §63.11237 definition of a boiler, the auxiliary boiler will exclusively fire natural gas and pursuant to 40 CFR §63.11195(e), is exempt. In addition, the proposed HRSG with DB meets the definition of a "waste heat boiler" and the proposed dew point heater meets the definition of a "process heater" and are excluded from the definition of a "boiler" per 40 CFR §63.11237. Therefore, pursuant to 40 CFR Part 63, Subpart JJJJJJ there are no applicable requirements for the proposed Project as long as the auxiliary boiler and dew point heater exclusively fire natural gas.

4.3.4 Requirement to Obtain an Operating Permit

In addition to applying for an Installation Permit, AEC will apply for a Federal TVOP as required under ACHD regulations Article XXI Air Pollution Control Regulations Part C. ACHD issues TVOP and is the delegated authority for enforcing and implementing the Federal TVOP. The Project will qualify as a major source of regulated pollutants; however, the Project will not be major for HAPs. In addition, the applicability of NSPS and NESHAP regulations trigger TVOP applicability.

Once an Installation Permit has been issued, AEC will prepare an TVOP application for submittal to ACHD. The Operating Permit will be submitted within 6-months of the expiration of the Installation Permit and no earlier than 18 months of the expiration date. The requirements of the TVOP application are specified in Article XXI Air Pollution Control Regulations Part C Subpart 1 §§2103.11 and 2103.21.

4.3.5 Cross State Air Pollution Rule (CSAPR)

CSAPR was first finalized by U.S. EPA on July 6, 2011. The timing of the rule implementation was impacted by several court decisions since its finalization including a stay of implementation. On October 23, 2014, the District of Colombia (D.C.) Circuit Court ordered that U.S. EPA's motion to lift the stay of CSAPR be granted. CSAPR Phase 1 implementation began in 2015, with Phase 2 beginning in 2017. The final rule requires power plants in 28 states to decrease annual SO_2 and NO_X emissions to help downwind areas realize attainment with the O_3 and $PM_{2.5}$ NAAQS.

Therefore, AEC must meet the requirements of CSAPR codified in 40 CFR Part 97, Subparts AAAAA and BBBBB [relating to the Transport Rule (TR) NO_X Annual Trading Program and TR NO_X Ozone Season Group 1 Trading Program] and 40 CFR Part 97, Subpart CCCCC (as it relates to TR SO_2 Group 1 Trading Program). To demonstrate compliance with CSAPR, AEC will implement NO_X CEMS requirements in accordance with 40 CFR Part 75, Subpart B §75.12 and

Subpart H. In addition, AEC will implement fuel flow based SO_2 monitoring system requirements (in lieu of continuous SO_2 pollutant concentration and exhaust flow monitors) for gas-fired units pursuant to 40 CFR Part 75, Subpart B §75.11(d)(2) and Appendix D. Furthermore, the Project will comply with the fuel flow and heat input monitoring system requirements for gas-fired units pursuant to 40 CFR Part 75, Appendix D. To ensure compliance with 40 CFR Part 75, AEC will submit a monitoring plan for the proposed unit. By complying with the applicable monitoring requirements identified in 40 CFR Part 75, the Project will meet the requirements of 40 CFR §§97.430 – 97.434 and 40 CFR §§97.530 through 97.534. The CSAPR application for the Project is provided in Appendix G.

4.3.6 **Acid Rain Program**

The ARP is codified in 40 CFR Parts 72 through 78 and addresses Title IV of the CAA which aims to reduce acid rain by reduction of SO_2 and NO_X emissions from existing and new utility units that have a nameplate electricity generation capacity greater than 25 MW. The proposed CT and HRSG with DB, and auxiliary boiler are subject to the ARP and AEC will comply with the applicable provisions of the following parts:

- 40 CFR Part 72 – Permits Regulation
- 40 CFR Part 73 – Sulfur Dioxide Allowance System
- 40 CFR Part 75 – Continuous Emission Monitoring
- 40 CFR Part 77 – Excess Emissions

The Phase II Acid Rain permit application required under 40 CFR Part 72 must be filed at least 24 months before the unit commences operation of any mechanical, chemical or electronic processes. The application must include the date that the unit will commence commercial operation and the deadline for monitoring certification (i.e., 90 days after commencement of commercial operation). The Acid Rain permit application for the Project is provided in Appendix G.

AEC will arrange for the establishment of an SO_2 emissions account for the Project. AEC will be responsible for obtaining the necessary emissions allowances and then overseeing the tracking, holding, and transfer of the allowances.

AEC will develop a Title IV Acid Rain monitoring plan as required pursuant to 40 CFR Part 72. The plan will include the installation, proper operation, and maintenance of CEMs or approved monitoring provisions under 40 CFR Part 75 for NO_X, SO_2, O_2, and CO_2.

The ARP NO_X emissions reduction provisions contained at 40 CFR Part 76 do not apply to the Project. Although there is an auxiliary boiler for the Project, the auxiliary boiler is not coal-fired; and thus, it is not subject to regulation per 40 CFR Part 76. The CT and DB do not meet the definition of a boiler and are not subject to regulation per 40 CFR Part 76.

4.3.7 Risk Management Plan (RMP)

The RMP Rule, promulgated at 40 CFR Part 68, implements Section 112(r) of the CAAA of 1990 and establishes guidance for chemical accident prevention at facilities using, storing, manufacturing, or handling extremely hazardous substances. The RMP Rule includes a "List of Regulated Substances" including their synonyms and threshold quantities to help assess if a process is subject to the RMP Rule or the *General Duty Clause* of CAA Section 112(r).

Aqueous ammonia, which will be used by the SCR system for NO_X emissions control, is a Regulated Substance under Section 112(r). The threshold quantity in the RMP Rule List of Regulated Substances pursuant to 40 CFR §68.130 for aqueous ammonia is 20,000 pounds with a concentration 20% or greater. Because aqueous ammonia will be stored on-site in one storage tank with a capacity of 20,000 gallons with a concentration of less than 20% by weight, the concentration applicability criteria will not be met and the provisions of 40 CFR Part 68 will not apply.

4.4 ACHD AIR QUALITY RULES AND REGULATIONS

In addition to the Federal air regulations that ACHD implements and enforces, ACHD enforces its own regulations related to air quality. The majority of the ACHD air quality regulations related to the CAA Section 110 have been approved by U.S. EPA under 40 CFR Parts 51 (SIP). ACHD enforcement and implementation of air quality regulations related to the NSPS and NESHAPs have been approved by U.S. EPA's at 40 CFR Parts 60 and 63 respectively.

This section highlights the applicable ACHD air quality regulations and citations with regulatory requirements pertinent to the Project. The applicable ACHD air quality regulations are enforced by ACHD. The potentially applicable ACHD regulations include the following:

- Part A – General
- Part B – Permits Generally
- Part C – Operating Permits
- Part D – Pollutant Emission Standards
- Part E – Source Emission and Operating Standards
- Part F – Air Pollution Episodes
- Part G – Methods
- Part H – Reporting, Testing, & Monitoring
- Part I – Enforcement

4.4.1 Part A – General

Part A describes the purpose of the air quality program, contains definitions, identifies the NAAQS and ACHD ambient air quality standards, and provides other general requirements for the control and prevention of air pollution within Allegheny County. This Project will comply with the general provisions outlined in Part A.

4.4.2 Part B – Permits Generally

As a new source, a complete application for an Installation Permit is required to be submitted for the Project. This document, prepared in accordance with §2102.04(a) and (b), represents the required Installation Permit application. §2102.04(a) addresses general permitting requirements and §2102.04(b) addresses the standards for issuance of an Installation Permit. Specifically, §§2102.04(b)(1)-(10) identifies the contents of a complete Installation Permit application which includes new source requirements for attaining and maintaining compliance with the NAAQS and applying the Best Available Control Technology (BACT) to the emissions units. In accordance with §2102.04(d), a Fugitive Dust Prevention and Control Plan (Plan) for the implementation of all reasonable actions to prevent fugitive dust from becoming airborne during construction activities is included in Appendix H.

AEC will be permitted as a major stationary source for regulated NSR pollutants and will be subject to the NNSR and PSD permitting requirements §2102.06 and §2102.07 respectively. The Project will be subject to §2102.05 and will provide documentation of the required interstate notifications to Maryland, Ohio, and West Virginia as part of this Installation Permit Application.

Application and administrative fee requirements associated with Installation Permit applications are specified in §2102.10. Because the Project is subject to NNSR, PSD, NSPS and NESHAP standards, AEC is required to include with this Application a $22,700 fee in accordance with §2102.10(b). In addition, in accordance with §2102.10(c), an Annual Installation Permit Administration fee of $750.00 has also been submitted in advance of an approval of the Installation Permit. Therefore, the total initial permit fee (Installation Permit fee and administration fee) for the Project is $23,450. A check payable to the "Allegheny County Air Pollution Control Fund" in this amount will be submitted in conjunction with this Application.

4.4.3 Part C – Operating Permits

Pursuant to §2103.10, the Part C TVOP requirements apply to all emissions units and air pollution control equipment located in Allegheny County. As a major stationary source AEC will be subject to the requirements for developing an application; tasks associated with the issuance of an operating permit; demonstrating compliance via record keeping, monitoring, and reporting; and paying fees. A complete and timely initial application for an Operating Permit for the Project will be prepared and submitted in accordance with the applicable provisions of Part C.

4.4.4 Part D – Pollutant Emission Standards

Part D identifies emissions standards for various processes. The specific emissions standards for the Project are discussed in the following sections.

4.4.4.1 Visible Emissions

Standards for visible emissions are addressed in §2104.01. §2104.01(a)(1)–(2) prohibit visible emissions other than uncombined water equal to or in excess of 20% for a period or periods aggregating more than three minutes in any 60 minute period or equal to or in excess of 60% at any time. Visible emissions resulting solely from the cold start of fuel-burning or combustion equipment are excluded from these requirements if ACHD is notified in writing 24-hours in advance of the cold start in accordance with §2108.01(d). To demonstrate compliance with the visible emissions requirements, U.S. EPA Method 9 will be conducted on a periodic basis. The emissions units associated with the Project will be maintained and operated in accordance with manufacturer's recommendations, which will ensure that the standards for visible emissions are met.

4.4.4.2 Particulate Mass Emissions

Standards for particulate mass emissions, which are referenced throughout this Application as PM (i.e., particulate matter) emissions, for fuel-burning or combustion equipment are addressed in §2104.02(a). Pursuant to §2104.02(a)(1), PM emissions from the CT and HRSG with DB will not exceed the maximum allowable pounds per actual heat input rate of 0.015 lb/MMBtu. To demonstrate compliance with this emissions limit, the CT and HRSG with DB will be operated in accordance with manufacturer's recommendations. In addition, the CT and HRSG with DB will comply with this emissions limit by meeting BACT requirements discussed in Section 5.3.

Pursuant to §2104.02(a)(1), PM emissions from the natural gas-auxiliary boiler and dew point heater will not exceed the maximum allowable pounds per actual heat input rate of 0.008 lb/MMBtu. To demonstrate compliance with this emissions limit, the auxiliary boiler and dew point heater will be operated in accordance with the manufacturer's recommendations for proper maintenance and operation. In addition, the auxiliary boiler and dew point heater will comply with this emissions limit by meeting the BACT requirements discussed in Sections 5.4.4 and 5.5.4.

Pursuant to §2104.02(a)(1), PM emissions from the ULSD-fired emergency generator and fire water pump will not exceed the maximum allowable pounds per actual heat input rate of 0.28 lb/MMBtu. To demonstrate compliance with this emissions limit, the emergency generator and the fire water pump will be operated in accordance with the manufacturer's recommendations for proper maintenance and operation. In addition, the emergency generator and fire water pump will comply with this emissions limit by meeting the BACT requirements discussed in Sections 5.5.4

and 5.6.4 Additionally, the engines are required to meet the 40 CFR Part 60 Subpart IIII Tier 2 emissions standard of 0.2 g/kW-hr of PM.

4.4.4.3 Sulfur Oxide Emissions

Standards for sulfur oxide (SO_X) emissions, expressed as SO_2, for fuel-burning or combustion equipment are addressed in §2104.03(a). Pursuant to §2104.03(a)(1), SO_2 emissions from equipment fired only with natural gas (i.e., the CT and HRSG with DB, auxiliary boiler, and dew point heater) will not exceed the respective PTE of the equipment. AEC will comply with §2104.03(a)(1) by firing natural gas in the CT and HRSG with or without DB, auxiliary boiler, and dew point heater.

Pursuant to §2104.03(a)(2), SO_2 emissions from equipment that fires fuel other than natural gas and liquefied petroleum gas (i.e., the emergency generator and the fire water pump) will not exceed 1.0 lb/MMBtu of actual heat input. AEC will comply with the emissions limit by firing ULSD in the emergency generator (approximately 0.7 MMBtu/hr) and fire water pump (approximately 2.6 MMBtu/hr) and by meeting the BACT requirements discussed in Sections 5.6.5 and 5.7.5. The fuel fired in the engines will meet §2104.10 because the sulfur in the ULSD is less than 500 ppm.

4.4.4.4 Odor Emissions

Odor emissions are addressed in §2104.04. Pursuant to §2104.04(a), the release of emissions of any malodorous matter from a source, in such a manner that the malodors are perceptible beyond the Project's property is not permitted. The operation of the emissions units associated with the Project will not produce malodors. AEC will address malodors if detected.

4.4.4.5 Stack Heights

Per §2104.07, the emissions limits for any emissions unit shall not be dependent on a stack height that is in excess of Good Engineering Practice (GEP), or through the use of other dispersion techniques. A GEP analysis for the stacks at the Facility will be conducted to establish the maximum creditable heights and to ensure compliance with §2104.07.

4.4.5 **Part E – Source Emission and Operating Standards**

Part E sets emissions and operating standards for specific types of emissions sources. The specific emissions and operating standards outlined in this Part that are applicable to the Project are discussed in the following sections. The Facility will be a major stationary source for NO_X and VOC, however, it is not subject to §2105.06 because the Facility is not constructed prior to the rule applicability date of November 1, 1992.

4.4.5.1 Operation and Maintenance

§2105.03 requires that all air pollution control equipment shall be properly installed, maintained, and operated consistently with good air pollution control practices. The Project will comply with §2105.03.

4.4.5.2 Volatile Organic Compound Storage Tanks

Requirements for VOC storage tanks are addressed in §2105.12. The vapor pressure of ULSD is 0.02 pounds per square inch absolute (psia) and the vapor pressure of common lubricating oil is 0.00015 psia. Therefore, the 3,500 gallon emergency diesel generator storage tank 500 gallon fire water pump storage tank, and the 10,000 gallon lubricating oil tank will not be subject to §2105.12 as this regulation applies to VOC with a vapor pressure of 1.5 psia or greater.

4.4.5.3 Fugitive Emissions

Requirements for fugitive emissions are addressed in §2105.49. AEC will minimize fugitive emissions by taking reasonable actions to prevent visible emissions outside the property boundary. Additional requirements for miscellaneous fugitive emissions sources are addressed in §§2105.40 – 2105.47 and apply in specific geographical locations within Allegheny County as defined in §2105.48. Because the Project is not within the areas specified in §2105.48, the requirements of §§2105.40 – 2105.47 are not applicable.

4.4.5.4 Open Burning

§2105.50 states that no open burning of any material can be conducted, except when ACHD has issued an open burning permit. AEC does not anticipate the need to conduct any open burning. However, if open burning is required, AEC will comply with the requirements of §2105.50.

4.4.5.5 NO_X Allowance Requirements

As identified in §2105.100, compliance is required with the PADEP NO_X Budget and NO_X Allowance Trading Program for NO_X affected sources located in Allegheny County and subject to 25 Pa Code §§123.101 – 123.120. AEC will establish a compliance account with PADEP and secure the required NO_X allowances. Subsequently, AEC will conduct the necessary NO_X CEMS monitoring and report NO_X emissions to PADEP as appropriate. AEC will also report information related to §2105.100 to ACHD as necessary (e.g., name of NOx Allowance Tracking System -- NATS account representative and alternate).

4.4.6 Part F – Air Pollution Episodes

Part F establishes standards and protocol for air pollution episodes. The purpose of Part F is to provide ACHD with the authority to decrease the severity and duration of air pollution episodes. While there are no applicable rules of this Part that apply to the Project, AEC will operate and maintain the Project consistent with good industrial practices and safe operating procedures. If requested by ACHD, AEC will prepare and submit a source curtailment plan to address the reduction of emissions during air pollution episodes.

4.4.7 Part G – Methods

Part G provides definitions and emissions test methods, analytical procedures, and ambient air monitoring methodologies to determine compliance with emissions standards, source standards, and ambient air quality standards. This Project will use the appropriate emission testing methods to demonstrate compliance with the applicable emissions standards.

4.4.8 Part H – Reporting, Testing, & Monitoring

Part H outlines requirements for reporting, notification, testing and, monitoring. AEC will conduct emissions testing and comply with the reporting, testing, and monitoring requirements as they apply to the Project. AEC will provide the necessary 24-hour notification prior to the shut down of pollution control equipment or upon the event of a cold start. Upon malfunction or breakdown of emissions units and control devices, AEC will provide notification to ACHD within 60 minutes of such occurrence and written notification within 7 days. AEC will also install, operate, and maintain NO_X CEMS in accordance with §2108.03(b) and will comply with the calibration, quality assurance, and reporting requirements as applicable.

4.4.9 Part I – Enforcement

Part I identifies the enforcement policies of ACHD pertaining to emissions units for the purpose of determining compliance. This Project will comply with the general provisions outlined in Part I by allowing ACHD access to the Facility and allowing ACHD access to the records necessary to confirm compliance with applicable regulations.

5. CONTROL TECHNOLOGY ANALYSIS

As discussed in Section 4, the proposed Project will be classified as a major source under the Allegheny County and Federal NSR regulations. Therefore, BACT (for attainment pollutants) and LAER (for nonattainment pollutants) evaluations will be required for those NSR regulated pollutants that trigger NSR applicability. In addition, Allegheny County requires that BACT be applied to new sources, regardless of whether the Project triggers NSR, pursuant to ACHD Article XXI §2102.04.b.6. While the procedures for conducting a BACT analysis are not explicitly defined in Article XXI, the analyses included herein were performed by conducting a "top-down" analysis as outlined in U.S. EPA's Draft *"New Source Review Workshop Manual*[1]*,"* as discussed in Section 5.1 below.

Based on the Project-related potential emissions summarized in Table 3-14, BACT and LAER evaluations are required for several NSR regulated pollutants as required under the NSR regulations. Specifically, NSR BACT analyses are required for those emissions units that emit the following pollutants: CO, PM, PM_{10}, H_2SO_4, and GHG. Because all of Pennsylvania, including Allegheny County is part of the Northeast OTR, the state is classified as a marginal nonattainment area with respect to the O_3 NAAQS. Therefore, because the Project is major for NO_X and VOC (precursor pollutants for O_3), a LAER analysis is required for those emissions units emitting either of these two pollutants. Although the Project is located in a nonattainment area for SO_2 and $PM_{2.5}$ the Project-related emissions for these two pollutants are not major (i.e., the proposed project emissions are less than the 100 tpy threshold). As a result, a BACT analysis was performed for $PM_{2.5}$ and SO_2 following the same procedure as PSD BACT to meet the requirements of ACHD BACT for new sources per §2102.04.b.6. It should be noted that NO_X is a precursor pollutant for $PM_{2.5}$, and thus, the LAER analysis that is performed for O_3 will also meet the LAER requirements

[1] U.S. EPA, Draft New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, October 1990 (1990 Workshop Manual).

for NO_X as a precursor pollutant to $PM_{2.5}$. A summary of the control evaluations that have been prepared by pollutant is provided in Table 5-1

The approaches that AEC followed to evaluate BACT and LAER are provided in Sections 5.1 and 5.2 respectively. The individual BACT and LAER determinations are provided in the subsequent sections.

Table 5-1
Summary of Control Evaluations Required
Invenergy LLC – Allegheny Energy Center

Pollutant	Control Evaluation Required
NOx	LAER
CO	BACT
VOC	LAER
PM	BACT
PM_{10}	BACT
$PM_{2.5}$	ACHD BACT
SO_2	ACHD BACT
H_2SO_4	BACT
GHG	BACT

5.1 OVERVIEW OF BACT EVALUATION METHODOLOGY

BACT analyses were conducted for CO, PM, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4, and GHG for each new emissions unit:

- CT and HRSG with DB
- Auxiliary boiler,
- Dew point heater,
- Emergency generator, and
- Fire water pump engine
- Circuit breakers
- Natural gas piping components
- Roadways

As presented in Table 3-14, lead (Pb) emissions for the Project are 0.00094 tons per year (tpy). Therefore, Pb emissions were assumed to be insignificant when compared to the NSR significant emissions rate of 0.6 tpy and were not evaluated for NSR BACT and ACHD BACT.

BACT determinations are case-by-case analyses that involve an assessment of the applicable control technologies capable of reducing emissions of a pollutant. The determinations are conducted using a "top-down" approach considering technical feasibility, as well as, economic, environmental, and energy impacts. BACT is defined in ACHD Article XXI §2101.20 as follows:

> *Best available control technology (BACT) — an emission limitation based on the maximum degree of reduction of each air contaminant regulated by [Article XXI], which [ACHD] determines on a case-by-case basis to be achievable taking into account the energy, environment, and economic impacts and other costs. In no event shall application of BACT result in emissions of any air contaminant exceeding the emissions allowed under any applicable New Source Performance Standard (NSPS), any National Emission Standards for Hazardous Air Pollutants (NESHAP), or any Reasonably Available Control Technology (RACT) emission limit under [Article XXI].*

While there is no legal requirement to perform BACT analyses utilizing a specific criteria or process, the BACT analyses presented in this application follow U.S. EPA guidance outlined in Chapters B and G of the U.S. EPA Draft *"New Source Review Workshop Manual*[2]*"* A "top-down" BACT analysis includes the following five basic steps:

- Step 1: Identify Available Control Technologies
- Step 2: Eliminate Technically Infeasible Options
- Step 3: Rank Remaining Control Technologies by Control Effectiveness
- Step 4: Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies
- Step 5: Identify BACT

The five-step approach taken to perform "top-down" BACT analyses for each of the emissions units is described below. The process is repeated for each pollutant emitted from the unit for which BACT applies. Step 4 in the process may be omitted if the most efficient emissions control methodology is selected.

5.1.1 Best Available Control Technology Step 1 – Identify Available Control Technologies

The first step in the "top-down" BACT process is to identify "available" control options. Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and pollutant under evaluation, with a focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type in which the demonstration has occurred.

For the Project, the scope of potentially applicable control options was determined based on a review of the RACT/BACT/LAER Clearinghouse (RBLC) database for entries within the last 10

[2] U.S. EPA, Draft New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, October 1990 (1990 Workshop Manual).

years.[3] The entries identified from the RBLC database were supplemented with other recently permitted facilities not currently listed in the RBLC. Entries that were not representative of the emissions unit, proposed fuel, or operating condition or were proven to not meet an emissions limit were excluded from further consideration. Upon completion of the RBLC search, relevant vendor information, pending permit applications, and issued permits not included in the RBLC were also reviewed. Sources of information searched included:

- In-house experts
- Similar permitting projects
- State air regulatory agency contacts and websites
- California Air Resources Board (CARB) BACT Clearinghouse
- New Jersey's State of the Art (SOTA) Manual for Stationary Combustion Turbines
- Technical books and articles
- The U.S. EPA Region IV National Combustion Turbine Spreadsheet[4]
- State permits issued for similar sources that have not yet been entered into the RBLC and
- Guidance documents and personal communications with state agencies

5.1.2 Best Available Control Technology Step 2 – Eliminate Technically Infeasible Options

In the second step of the BACT analysis, an available control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. A demonstration of technical infeasibility must be documented and show, based on physical, chemical, or engineering principles, that technical reasons would preclude the successful use of the control option on the emissions unit under review. U.S. EPA generally considers a technology to be technically feasible if it has been demonstrated and operated successfully on the same type of emissions unit under review or is available and applicable to the emissions unit type under review. If a technology has been operated on the same type of emissions unit, it is presumed

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[3] RACT/BACT/LAER Clearinghouse (RBLC). http://cfpub.epa.gov/rblc/
[4] U.S. EPA Region IV National Combustion Turbine Spreadsheet. https://19january2017snapshot.epa.gov/.../ct_rtr_facility_list_draft_09292016_0.xlsx

to be technically feasible. However, an available technology from Step 1 cannot be eliminated as infeasible simply because it has not been used on the same type of source that is under review. If the technology has not been operated successfully on the type of source under review, then questions regarding "availability" and "applicability" to the particular source type under review should be considered for the technology to be eliminated as technically infeasible.

5.1.3 Best Available Control Technology Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The third step of the BACT process calls for the remaining control technologies to be listed in order of overall control effectiveness for the pollutant under review. The most effective control alternative (i.e., the option that achieves the lowest emissions level) should be listed at the top and the remaining technologies ranked in descending order of control effectiveness. The ranking of control options in Step 3 determines where to start the "top-down" selection process in Step 4. In determining and ranking technologies based on control effectiveness, facilities may include information on each technology's control efficiency (e.g., percent pollutant removed, emissions per unit product), expected emissions rate (e.g., tpy, lb/hr), pounds per unit of input, ppmvd, and expected emissions reduction (e.g., tpy). The metrics chosen for ranking should best represent the array of control technology alternatives under consideration for the pollutant included in the evaluation. If the top ranked control is selected prior to Step 4, then Step 4 may not be necessary.

5.1.4 Best Available Control Technology Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

In the fourth step of the BACT analysis, facilities can consider the economic, environmental, and energy impacts arising from each remaining option under consideration. Accordingly, after available and technically feasible control options have been ranked in terms of control effectiveness (Step 3), facilities should consider specific economic, environmental, and energy impacts identified with those technologies to either confirm that the "top" control alternative is appropriate or inappropriate. The "top" control option should be established as BACT unless the applicant demonstrates that the economic, environmental, and energy impacts are so constraining such that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on. Both direct and indirect impacts of the emissions control option or strategy being evaluated should be considered.

5.1.5 Best Available Control Technology Step 5 – Identify BACT

During the fifth step of the BACT analysis, the most effective control option not eliminated in Step 4 should be selected as BACT for the pollutant and emissions unit under review. BACT should include averaging times and units of measurement to make BACT enforceable as a practical matter.

It is important to note that not all CTs are the same. Different makes (manufacturers) and models of CTs are designed to meet different objectives specific to a given project. For instance, higher combustion zone temperatures and residence times generally mean more complete combustion, lower VOC emissions, and higher efficiency. However, higher temperatures also generally mean higher NO_X formation. Therefore, if a CT is designed to be more efficient (higher temperature) or to meet a certain VOC level, then its NO_X emissions might be higher. For this reason, CTs are considered inherently different and often cannot be directly compared. In addition, if a company plans to install a CT and HRSG because it meets its specific business purposes, the BACT process is not intended to force that company to install an alternative specific CT model (e.g., GE, Siemens or Mitsubishi). The intention of BACT is to install the best air pollution control technology available on a given emissions unit. This means that emissions from different CTs controlled by the same technology may vary. Therefore, throughout this BACT analysis, emissions limits associated with different CT projects may not be directly comparable due to the differences in manufacturers and models of CTs and HRSGs and are evaluated on a case-by-case basis.

5.2 OVERVIEW OF LAER ANALYSIS METHODOLOGY

The LAER determination for NOx and VOC was conducted in accordance with the requirements of ACHD Article XXI §2102.06. LAER for new emissions units is defined in ACHD Article XXI §2101.20 as the emissions rate that is the most stringent of:

(a) The most stringent emission limitation contained in any state's implementation plan approved by the EPA for such class or category, unless the applicant demonstrates that such limitation is not achievable;

(b) The lowest emission rate achieved in practice by such class or category of source; or

(c) Any applicable NSPS established by the EPA.

Unlike BACT, LAER is determined without regard to the economic impact of pollutant reduction. A LAER is considered not achievable if the cost of control is so great that a major new source could not be built or operated, if it redefines the source of emissions, or has not been consistently demonstrated in practice. In addition, because LAER requirements are at least as stringent as BACT, the LAER analysis will also satisfy the BACT demonstration for NOx and the ACHD BACT demonstration for VOC. Like BACT, LAER determinations for specific models and manufacturers of CTs cannot automatically be assigned to other models and manufacturers of CTs. Finally, like BACT, AEC has not performed LAER analyses for sources of insignificant emissions. Specifically, AEC has not addressed LAER for the ULSD storage tanks and lubricating oil storage tank as these the tanks at the facility will emit less than 0.002 tpy of VOC combined.

A summary of proposed BACT and LAER limits for each new emissions unit is included as Table 5-2.

Table 5-2
Invenergy, LLC - Allegheny Energy Center
Summary of Proposed LAER/BACT Determinations

Pollutant	Fuel	Emissions Unit	Control	Limit	Units	Averaging Period
NO_X	Natural Gas	CT and HRSG with DB	Good combustion practices, dry low-NO_X combustor, and selective catalytic reduction	2.0	ppmvd @ 15% O_2	3-hour block
				30.9	lb/hr	
NO_X	Natural Gas	CT and HRSG without DB	Good combustion practices, dry low-NO_X combustor, and selective catalytic reduction	2.0	ppmvd @ 15% O_2	3-hour block
				27.9	lb/hr	
CO	Natural Gas	CT and HRSG with DB	Good combustion practices and catalytic oxidation	2.0	ppmvd @ 15% O_2	3-hour block
				18.8	lb/hr	
CO	Natural Gas	CT and HRSG without DB	Good combustion practices and catalytic oxidation	2.0	ppmvd @ 15% O_2	3-hour block
				17.0	lb/hr	
VOC (as CH_4)	Natural Gas	CT and HRSG with DB	Good combustion practices and catalytic oxidation	1.5	ppmvd @ 15% O_2	3-hour block
				8.1	lb/hr	
VOC (as CH_4)	Natural Gas	CT and HRSG without DB	Good combustion practices and catalytic oxidation	1.0	ppmvd @ 15% O_2	3-hour block
				4.9	lb/hr	
PM[a]	Natural Gas	CT and HRSG with DB	Good combustion practices and low sulfur fuel	0.0029	lb/MMBtu	Average of three stack test runs
				10.6	lb/hr	
PM[a]	Natural Gas	CT and HRSG without DB	Good combustion practices and low sulfur fuel	0.0042	lb/MMBtu	Average of three stack test runs
				8.2	lb/hr	
PM_{10}/$PM_{2.5}$[b]	Natural Gas	CT and HRSG with DB	Good combustion practices and low sulfur fuel	0.0058	lb/MMBtu	Average of three stack test runs
				21.1	lb/hr	
PM_{10}/$PM_{2.5}$[b]	Natural Gas	CT and HRSG without DB	Good combustion practices and low sulfur fuel	0.0084	lb/MMBtu	Average of three stack test runs
				16.5	lb/hr	
SO_2	Natural Gas	CT and HRSG with DB	Good combustion practices and low sulfur fuel	0.0014	lb/MMBtu	Average of three stack test runs
				5.6	lb/hr	
SO_2	Natural Gas	CT and HRSG without DB	Good combustion practices and low sulfur fuel	0.0014	lb/MMBtu	Average of three stack test runs
				5.1	lb/hr	
H_2SO_4	Natural Gas	CT and HRSG with DB	Good combustion practices and low sulfur fuel	0.00100	lb/MMBtu	Average of three stack test runs
				4.0	lb/hr	
H_2SO_4	Natural Gas	CT and HRSG without DB	Good combustion practices and low sulfur fuel	0.00101	lb/MMBtu	Average of three stack test runs
				3.6	lb/hr	
GHG (as CO2e)	Natural Gas	CT and HRSG	Oxidation catalyst in conjunction with implementing energy efficiency and using inherently lower-emitting processes, combustion practices, work practices, and design	6,468	Btu/kWh	N/A
GHG (as CO_2e)	Natural Gas	CT and HRSG	Oxidation catalyst in conjunction with implementing energy efficiency and using inherently lower-emitting processes, combustion practices, work practices, and design	749	CO_2e lb/gross MWh	N/A
NO_X	Natural Gas	Auxiliary Boiler	Good combustion practices, limited operating hours, ULNB, and FGR	0.01	lb/MMBtu	Average of three (3) test runs
				0.98	lb/hr	
CO	Natural Gas	Auxiliary Boiler	Good combustion practices and limited operating hours	0.04	lb/MMBtu	Average of three (3) test runs
				3.62	lb/hr	
VOC	Natural Gas	Auxiliary Boiler	Good combustion practices and FGR	0.004	lb/MMBtu	Average of three (3) test runs
				0.35	lb/hr	
PM[a]	Natural Gas	Auxiliary Boiler	Good combustion practices and low sulfur fuel	0.0018	lb/MMBtu	Average of three (3) test runs
				0.16	lb/hr	
PM_{10}/$PM_{2.5}$[b]	Natural Gas	Auxiliary Boiler	Good combustion practices and low sulfur fuel	0.00149	lb/MMBtu	Average of three (3) test runs
				0.1318	lb/hr	
SO_2	Natural Gas	Auxiliary Boiler	Good combustion practices and low sulfur fuel	0.0011	lb/MMBtu	Average of three (3) test runs
				0.1	lb/hr	
H_2SO_4	Natural Gas	Auxiliary Boiler	Good combustion practices and low sulfur fuel	0.000135	lb/MMBtu	Average of three (3) test runs
				0.01	lb/hr	
GHG (as CO2e)	Natural Gas	Auxiliary Boiler	Energy efficient design and work practices	Comply with Facility-wide limit		N/A
NO_X	Natural Gas	Dew Point Heater	Good combustion practices	0.011	lb/MMBtu	Average of three (3) test runs
				0.03	lb/hr	
CO	Natural Gas	Dew Point Heater	Good combustion practices	0.037	lb/MMBtu	Average of three (3) test runs
				0.11	lb/hr	
VOC	Natural Gas	Dew Point Heater	Good combustion practices	0.005	lb/MMBtu	Average of three (3) test runs
				0.02	lb/hr	
PM[a]	Natural Gas	Dew Point Heater	Good combustion practices and low sulfur fuel	0.0048	lb/MMBtu	Average of three (3) test runs
				0.01	lb/hr	
PM_{10}/$PM_{2.5}$[b]	Natural Gas	Dew Point Heater	Good combustion practices and low sulfur fuel	0.0015	lb/MMBtu	Average of three (3) test runs
				0.0045	lb/hr	
SO_2	Natural Gas	Dew Point Heater	Good combustion practices and low sulfur fuel	0.0011	lb/MMBtu	Average of three (3) test runs
				0.0033	lb/hr	
H_2SO_4	Natural Gas	Dew Point Heater	Good combustion practices and low sulfur fuel	0.000135	lb/MMBtu	Average of three (3) test runs
GHG (as CO2e)	Natural Gas	Dew Point Heater	Energy efficient design and work practices	Comply with Facility-wide limit		N/A
NO_X	ULSD	Emergency Generator Engine	Good combustion practices, low sulfur fuels, proper maintenance, and limited operating hours	4.56	g/hp-hr	Average of three (3) test runs
				30.74	lb/hr	
CO	ULSD	Emergency Generator Engine	Good combustion practices, low sulfur fuels, proper maintenance, and limited operating hours	2.61	g/hp-hr	Average of three (3) test runs
				17.6	lb/hr	
VOC	ULSD	Emergency Generator Engine	Good combustion practices, low sulfur fuels, proper maintenance, and limited operating hours	0.24	g/hp-hr	Average of three (3) test runs
				1.62	lb/hr	
PM[a]	ULSD	Emergency Generator Engine	Good combustion practices, low sulfur fuels, proper maintenance, and limited operating hours	0.15	g/hp-hr	Average of three (3) test runs
				1.01	lb/hr	
PM_{10}/$PM_{2.5}$[b]	ULSD	Emergency Generator Engine	Good combustion practices, low sulfur fuels, proper maintenance, and limited operating hours	0.17	g/hp-hr	Average of three (3) test runs
				1.17	lb/hr	
SO_2	ULSD	Emergency Generator Engine	Good combustion practices, low sulfur fuels, proper maintenance, and limited operating hours	0.0055	g/hp-hr	Average of three (3) test runs
				0.04	lb/hr	
H_2SO_4	ULSD	Emergency Generator Engine	Good combustion practices, low sulfur fuels, proper maintenance, and limited operating hours	0.00067	g/hp-hr	Average of three (3) test runs
				0.0045	lb/hr	
GHG (as CO2e)	ULSD	Emergency Generator Engine	Good combustion practices and limited operating hours	Comply with Facility-wide limit		N/A
NO_X	ULSD	Fire Water Pump Engine	Good combustion practices, low sulfur fuels, proper maintenance, and limited operating hours	2.85	g/hp-hr	Average of three (3) test runs
				1.77	lb/hr	
CO	ULSD	Fire Water Pump Engine	Good combustion practices, low sulfur fuels, proper maintenance, and limited operating hours	2.60	g/hp-hr	Average of three (3) test runs
				1.62	lb/hr	
VOC	ULSD	Fire Water Pump Engine	Good combustion practices, low sulfur fuels, proper maintenance, and limited operating hours	0.15	g/hp-hr	Average of three (3) test runs
				0.09	lb/hr	
PM[a]	ULSD	Fire Water Pump Engine	Good combustion practices, low sulfur fuels, proper maintenance, and limited operating hours	0.15	g/hp-hr	Average of three (3) test runs
				0.09	lb/hr	
PM_{10}/$PM_{2.5}$[b]	ULSD	Fire Water Pump Engine	Good combustion practices, low sulfur fuels, proper maintenance, and limited operating hours	0.17	g/hp-hr	Average of three (3) test runs
				0.11	lb/hr	
SO_2	ULSD	Fire Water Pump Engine	Good combustion practices, low sulfur fuels, proper maintenance, and limited operating hours	0.93	g/hp-hr	Average of three (3) test runs
				0.578	lb/hr	
H_2SO_4	ULSD	Fire Water Pump Engine	Good combustion practices, low sulfur fuels, proper maintenance, and limited operating hours	0.114	g/hp-hr	Average of three (3) test runs
				0.07	lb/hr	
GHG (as CO2e)	ULSD	Fire Water Pump Engine	Good combustion practices and limited operating hours	Comply with Facility-wide limit		N/A

Table 5-2
Invenergy, LLC - Allegheny Energy Center
Summary of Proposed LAER/BACT Determinations

Pollutant	Fuel	Emissions Unit	Control	Limit	Units	Averaging Period
GHG (as CO_2e)	N/A	Circuit Breakers	Installation of enclosed-pressure design with leak detection	96.58	CO_2e tpy	N/A
GHG (as CO_2e)	Natural Gas	Fugitive GHG Emissions from Natural Gas Piping	Implementation of auditory, visual, and olfactory (AVO) programs for fugitive control	274.73	CO_2e tpy	N/A
GHG (as CO_2e)	GHG	Natural Gas Piping Maintenance and Startup/Shutdown Line Purging	Implementation of AVO programs for fugitive control	794.8	CO_2e tpy	N/A
VOC	ULSD	Storage Tank Fugitive Emissions	Tank design	0.03	tpy	N/A
GHG (as CO_2e)	N/A	Facility-Wide	Good combustion practices	1,968,965	CO_2e tpy	N/A

[a] PM emission factor represents the filterable portion only.
[b] It is assumed that $PM_{10} = PM_{2.5}$. PM_{10} and $PM_{2.5}$ emissions factors account for both the filterable and condensable portions of PM.

5.3 CONTROL TECHNOLOGY ANALYSIS FOR THE COMBUSTION TURBINE AND HEAT RECOVERY STEAM GENERATOR

This section presents the BACT determination process for the CT and HRSG DB for CO, PM, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4, and GHG and the LAER determination for NO_X and VOC. Because the CT and DB exhausts will be combined and exhausted through the HRSG stack, BACT and LAER control evaluations will apply to both combustion sources and control technology evaluations will be considered following the DB or the HRSG combined exhaust (CT and DB). In addition, both the CT and the DB will have inherent design features that will reduce emissions of regulated NSR pollutants.

5.3.1 **LAER for Nitrogen Oxides (NO_X)**

The Project will be subject to LAER for NO_X, because potential emissions of NOx will be greater than the 100 tpy major stationary source threshold applicable to an O_3 precursor in the Northeast OTR. NO_X emissions from the Project are also subject to PSD review for NO_2, including BACT requirements. This section demonstrates that the proposed NO_X emissions and controls meet the requirements of LAER. Because LAER requirements are at least as stringent as BACT, the LAER analysis also satisfies the BACT demonstration for NOx.

NO_X is primarily formed by two mechanisms. The combination of elemental nitrogen and oxygen in the combustion air, within the high temperature environment of the combustor, generate thermal NO_X. The oxidation of nitrogen, via combustion contained in the fuel, generate fuel NO_X. Although natural gas contains free nitrogen, it does not contain fuel bound nitrogen; therefore, NO_X emissions from CTs and HRSG DBs combusting natural gas originate as thermal NO_X. The rate of formation of thermal NO_X is a function of residence time and free oxygen and exponentially increases with peak flame temperature.

5.3.1.1 Identify the Most Stringent State Implementation Plan Limitation in Any State

As part of a LAER analysis the most stringent emissions limitations that are contained in the SIP of any State for such class or category of stationary sources were identified. States that contain the most severe ozone nonattainment areas typically contain the most stringent NO_X limits in their SIPs. Thus, the NO_X control rules potentially applicable to natural gas CTs and HRSG with and without DBs were reviewed and summarized for the following states and/or Air Quality Management Districts (AQMD) in Table 5-3.

Table 5-3
NOX SIP Limitations in Nonattainment States and AQMD for CTs and HRSGs with and without DBs
Invenergy LLC – Allegheny Energy Center

State or AQMD	Regulatory Limit	Citation
Bay Area AQMD, CA	5 ppmvd @ 15% O_2 for natural gas-fired stationary gas turbine < 500 MMBtu/hr (equivalent to 0.15 lb/MMBtu)	BAAQMD Regulation 9, Rule 9, 9-9-301
San Joaquin Valley Unified (SJVU) AQMD	3 ppmvd @ 15% O_2 for enhanced option	SJVUAQMD Rule 4703, Stationary Gas Turbines, Tier 2, enhanced limit
Texas Commission on Environmental Quality	42 ppmvd @ 15% O_2 for natural gas-fired stationary gas turbines greater than or equal to 30 MW	Chapter 117 – Control of Air Pollution from Nitrogen Compounds §117.1005
New Jersey Department of Environmental Protection	1.3 lb/MWh for natural gas-fired, greater than 25 MW combined-cycle, non-HEDD unit	New Jersey Administrative Code, Title 7:27-19.5, Table 6
Massachusetts Department of Environmental Protection	42 ppmvd @ 15% O_2, burning only natural gas	310 CMR 7.19 – Reasonably Available Control Technology for Sources of Nitrogen Oxides

Table 5-3
NOX SIP Limitations in Nonattainment States and AQMD for CTs and HRSGs with and without DBs
Invenergy LLC – Allegheny Energy Center

State or AQMD	Regulatory Limit	Citation
New York State Department of Environmental Conservation	42 ppmvd @ 15% O_2, burning only natural gas	6 NYCRR, Chapter III, Part 227: Stationary Combustion Installations, Subpart 227-2 - Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_X)
Connecticut Department of Environmental Protection	55 ppmvd for a gas-fired turbine engine rated at 100 MMBtu/hr or more at a Major Stationary Source of NO_X	RCSA 22a-174-22 Control of Nitrogen Oxides Emissions
Pennsylvania Department of Environmental Protection	0.17 lb/MMBtu for stationary combustion turbine rated at greater than 250 MMBtu/hr that is not subject to CAIR NO_X Trading programs	Title 25 of the PA Code, Subpart C, Article III Air Resources § 129.202. Additional NO_X Requirements for stationary combustion turbines
Florida Department of Environmental Protection	0.5 lb/MMBtu NOx when firing natural gas	Chapter 62-296.570, F.A.C., Stationary Sources – Emission Standards, Reasonably Available Control Technology
Georgia Department of Natural Resources, Environmental Protection Division	6 ppmvd @ 15% O_2 for natural gas-fired stationary combustion turbines	Chapter 391-3-1, Rule: .02 Provisions. (nnn) NO_X emissions from large stationary gas turbines
Illinois Environmental Protection Agency	42 ppmvd @ 15% O_2, burning only natural gas	Title 35, Illinois Administrative Code, Subtitle B, Chapter I, Subchapter C, Part 217 – Nitrogen Oxides Emissions, section 217.388

The most stringent NO_X emission limitation applicable to natural gas-fired CTs and HRSG with and without DBs identified from this review of SIPs, comprising the most severe ozone non-attainment areas was 3 ppmvd @ 15% O_2 for NO_X (San Joaquin Valley Unified and AQMD).

Additionally, pursuant to the requirements of NSPS 40 CFR Part 60, Subpart KKKK for the proposed CT with HRSG and DB must comply with the following NO_X emissions standards for a new turbine firing natural gas with a heat input at peak load of greater than 850 MMBtu/hr:

- 40 CFR §60.4320(a) and Table 1 – NO_X
    - 15 ppm at 15% oxygen (O_2), or
    - 0.43 pounds per megawatt hour (lb/MWh) of useful output

Thus the Project's proposed NO_X emission limit for the CT and HRSG with and without DB firing of 2 ppmvd @ 15% O_2 is more stringent than both the most stringent SIP limitation found and NSPS Subpart KKKK.

In the following sub-sections, AEC has completed a top-down BACT analyses solely as a demonstration that the most stringent and appropriate control technologies are proposed for this project to meet the proposed LAER limits for NO_X as a precursor to O_3 and BACT for NO_2 without considering the cost of tons of pollutant removed.

5.3.1.2 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling NO_X emissions from a CT and HRSG DB. Maintaining optimum combustion efficiency or implementing appropriate maintenance procedures are examples of good combustion practices.

Water or Steam Injection

Water or steam injection is an example of a "front end" NO_X control technology. The addition of an inert diluent, such as water or steam, into the high temperature region of the CT flame controls NO_X formation by quenching peak flame temperatures. Increasing the water-to-fuel ratio employed with this technique increases the control of NO_X emissions. However, flame instability occurs when the water-to-fuel ratio becomes too high and emissions of CO and VOC increase due to incomplete combustion. This technique can cause wear on the turbine and combustors due to vibration and flame instability. This NO_X control technology is generally used for CTs and HRSGs firing fuel oil because of the higher combustion temperature achieved when firing fuel oil relative to natural gas.

Dry Low-NO_X Combustors

Dry low-NO_X (DLN) combustors are also an example of a "front end" NO_X control technology. The combustors limit peak flame temperature and excess O_2 with lean, pre-mix flames that achieve NO_X control equal to or better than water or steam injection. Some vendors offer this control technology on advanced heavy-duty industrial units.

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a control technology used to convert NO_X into diatomic nitrogen (N_2) and water (H_2O) using a catalyst. The reduction reactions used by SCR are most effective at O_2 levels above 2-3%. Base metals such as vanadium or titanium are often used for the catalyst due to their effectiveness as a control technology for NO_X and cost-effectiveness for use with natural gas combustion. In addition, a gaseous reductant such as anhydrous ammonia or aqueous ammonia ($NH_{3(aq)}$) is added to the flue gas and absorbed onto the catalyst.[5]

[5] The U.S. Department of Energy and Southern Company Services, Inc., "Control of Nitrogen Oxide Emissions: Selective Catalytic Reduction."

The downside of the catalysts used for SCR is the base metals' lack of high thermal durability and the catalyst's potential to oxidize SO_2 into SO_3. However, for use with combined-cycle gas turbines, the SCR reactor can be placed within a chamber in the HRSG where the flue gas temperature is within the operating range for base metal catalysts.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is a post-combustion control technology for NO_X emissions that uses a reduction-oxidation reaction to convert NO_X into N_2, H_2O, and CO_2. Like SCR, SNCR involves injecting ammonia (or urea) into the flue gas stream, which must be between approximately 1,400 and 2,000°F for the chemical reaction to occur.

SNCR is less expensive to operate than SCR since a catalyst is not required and, in theory, SNCR can control NO_X emissions with an efficiency similar to that of SCR (i.e., 90%). However, operating constraints on temperature, reaction time, and mixing often lead to less effective control efficiencies when using SNCR in practice, whereas SCR provides greater efficiency and quantity of NO_X removed.[6]

Low-NO_X Burners

The use of low NO_X burners (LNB) is another front-end control technology for limiting NO_X emissions from CTs and HRSGs. LNB delay the combustion by staging the air or fuel in multiple zones and thus limit peak flame temperatures. This results in uniform temperatures below the peak NO_X formation temperature range thereby lowering thermal NO_X emissions.

[6] https://www3.epa.gov/ttnecas1/models/SCRCostManualchapter_Draftforpubliccomment6-5-2015.pdf

Ultra-Low-NO_X Burners

Similar to LNB, the use of ultra-low NO_X burners (ULNB) is a front-end control technology for limiting NO_X emissions from CTs and HRSG DBs. While LNB limits peak flame temperature by separating combustion into multiple stages, an ULNB uses more advanced techniques, such as internal flue gas recirculation (FGR) and lean premixing of the air and fuel, to reduce NO_X emissions to negligible levels.

Oxidation Catalyst

Catalytic oxidation is an add-on control technology designed to reduce NO_X emissions. The catalysts are typically made of a precious metal and operate at temperatures in the range of 650 to 1,000°F.[7] The catalysts cause excess O_2 to react with NO_X to form CO_2. However, an issue with catalytic oxidation is the catalyst's susceptibility to poisoning by fine particles in the exhaust gas, which reduces the catalyst's effectiveness. For combined-cycle units, the most effective location of the catalyst to minimize the impact of fine particles on the catalyst is prior to the HRSG.

XONON™ Catalytic Combustor

The XONON™ catalytic combustor system is a NO_X control technology developed by Catalytica Energy Systems, Inc. It works by avoiding high temperatures caused by combustion. By integrating a catalyst into the combustor, XONON™ limits combustion temperatures to below the level where NO_X is formed. The XONON™ catalytic combustor system is a module that is installed inside the main component of the combustor. The module consists of a channel where pre-mixed fuel and air passes through the catalyst. It eliminates the fuel being combusted in a flame by combusting it using a catalyst at a lower temperature. Thus, NO_X formation is reduced.

[7] Catalytic Oxidizer. *Technology Transfer Network Clearinghouse for Inventories & Emissions Factors.* http://cfpub.epa.gov/oarweb/mkb/contechnique.cfm?ControlID=10

The XONON™ catalytic combustor system is now owned by Kawasaki Heavy Industries, Ltd. which is in the process of making the control technology available for gas turbine generators in the 1-1.4 MW range.

EMx™ Catalytic Absorption/Oxidation (Formerly SCONOX™)

EMx™ Catalytic Absorption/Oxidation is the second-generation of the SCONOX™ NO_X absorber technology that is distributed through EmeraChem. This technology does not utilize ammonia and is able to achieve emissions less than 1 ppm NO_X, undetectable CO, near zero VOCs, and greater than 50% control of fine particulate matter[8]. EMx™ uses a potassium carbonate (K_2CO_3) coated catalyst to reduce NO_X and CO emissions from natural gas fired turbines. The catalyst oxidizes CO to CO_2 and oxidizes nitric oxide (NO) to nitrogen dioxide (NO_2). The NO_2 absorbs onto the catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). The optimal temperature window for operation of the EMx™ catalyst is from 300˚F to 700˚F[9]. Periodically, dilute hydrogen gas is passed across the surface of the catalyst to regenerate the K_2CO_3 catalyst coating. This regeneration cycle converts KNO_2 and KNO_3 to K_2CO_3, water (H_2O), and elemental nitrogen (N_2). This makes K_2CO_3 available for further absorption.

5.3.1.3 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices are essential for the operation and life-span of the proposed CT and HRSG DB and will be used with the CT and HRSG DB. Therefore, good combustion practices are technically feasible for the CT and HRSG DB.

[8] http://emerachem.com/products/catalyst-coatings/adcat-catalyst-products
[9] http://www.rjmann.com/pdf%20files/emerachem/EMx.scono.technical.pdf

Water or Steam Injection

Although water or steam injection may be technically feasible for use on CTs and HRSG DBs when firing natural gas, based upon a review of RBLC search results, existing permits for similar combined-cycle CTs, CT vendor information and technical literature, water or steam injection has not been applied extensively or demonstrated superior NO_X control over the last 10 years , and is not considered further in this analysis.

Dry Low-NO_X Combustor

DLN combustors have been shown to be technically feasible for use on CTs and HRSG DBs and therefore are considered further in the analysis.

Selective Catalytic Reduction

SCR has been used historically on CTs and HRSG DBs and therefore, is considered technically feasible and considered further in the analysis.

Selective Non-Catalytic Reduction

SNCR requires a temperature window that is higher than the exhaust temperatures from natural gas-fired CTs. Therefore, SNCR is considered technically infeasible for the proposed CT and HRSG DB due to the temperature at which the turbines will operate, the residence time of the technology, and the lack of historical use of SNCR on CTs and HRSG DBs.

Low-NO_X Burners/ Ultra Low-NO_X Burners

LNB/ULNB have been found to be technically feasible for use on CTs and HRSG DBs and are therefore considered further in the analysis.

XONON™ Catalytic Combustor

Although developments to the XONON™ control technology are underway for gas turbines, such that it may become effective in gas turbine generators in the 1-1.4 MW range, this technology has not yet become available for application to larger turbine units similar to those proposed for the AEC Project. The current XONON™ catalytic combustor system has not been used on larger (i.e., greater than 1.4 MW)[10] combined-cycle turbines and therefore, it is not considered technically feasible. Based upon a review of RBLC search results, existing permits for similar combined-cycle CT projects, CT vendor information and technical literature, XONON™ control technology has not been applied extensively over the last 10 years for NO_X control.

EMx™ Catalytic Absorption/Oxidation (Formerly SCONOX™)

While EMx™ catalyst technology may have the potential to reduce NOx emissions below the proposed 2 ppmvd limit, it is not feasible to install on a new combined cycle CT as proposed by AEC. Some of the issues resulting in EMx™ technology infeasibility are:

- Lack of sufficient operating track record to be relied upon for LAER compliance.
- The demonstrated application for EMx™ is currently limited to combined cycle CTs under approximately 50 MW in size, while the CT proposed by AEC is a nominal 639 MW unit.
- The optimal operating temperature range is 300˚F to 700˚F, which is outside of the pre-control temperature range of the CT exhaust.
- The use of hydrogen for regeneration poses a serious safety concern.
- There are no RBLC entries for natural gas-fired combined cycle CTs that have implemented EMx™ technology to control NOx emissions.

Therefore, EMx™ is not considered further in this evaluation.

[10] Air Pollution Training Institute, Controlling NOx Formation in Gas Turbines, Chapter 7 https://www.apti-learn.net/lms/register/display_document.aspx?dID=39 (accessed on 02/19/2019)

5.3.1.4 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Although there are other technically feasible options (i.e., good combustion practices, water or steam injection, and/or LNB/ULNB) listed, the proposed use of DLN combustors and SCR is the most effective means of controlling NO_X emissions. Because AEC has proposed to employ SCR, along with good combustion practices, and DLN combustors for the CT and HRSG DB, ranking the remaining technologies is not necessary.

5.3.1.5 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Because NO_X required a LAER analysis the environmental, and/or energy impacts were not assessed in this LAER analysis.

5.3.1.6 Step 5 – Proposed LAER/BACT

AEC proposes to use SCR, DLN combustors, and good combustion practices as NO_X LAER for the CT and HRSG DB to achieve the emissions limits presented in Table 5-4.

Table 5-4
Proposed NO_X LAER (steady-state for the CT and HRSG
Invenergy LLC – Allegheny Energy Center

Emissions Unit	Fuel	LAER	Proposed Emissions Limit, 24-hour rolling	Short Term Limit Not to Exceed	Averaging Period
CT and HRSG DB firing	Natural Gas	SCR, DLN, and good combustion practices	2.0 ppmvd @ 15% O_2	30.9 lb/hr	Three-hour rolling
CT and HRSG without DB firing	Natural Gas	SCR, DLN, and good combustion practices	2.0 ppmvd @ 15% O_2	27.9 lb/hr	Three-hour rolling

To ascertain the appropriate LAER limits, AEC reviewed recently permitted facilities, the RBLC database, and other permits for similar CTs and HRSGs. This search identified several CTs and

HRSG DBs with emission rates less than the proposed 2.0 ppmvd NO_X @ 15% O_2 emissions limit, equivalent to 30.9 lb/hr for CTs and HRSG DBs firing operated on natural gas. Since all of the facilities identified below are permitted at the same concentration-based 2.0 ppmvd @ 15% O_2 NO_X emission rate and implementing the same control technology as proposed by AEC, the lower short-term hourly mass emission rates can be related to different CT operating profiles and combustion efficiencies.

- The Ineos Chocolate Bayou Facility is a cogeneration facility that uses two 35 MW CTs to generate power for the nearby Chocolate Bayou chemical plant. Permitted emission rates for the CTs are 11.43 lb/hr NO_X. These units are significantly smaller units than the proposed CT and HRSG DBs, with lower heat input, and are therefore not directly comparable.
- The St. Charles Power Station (Louisiana) uses Mitsubishi Hitachi Power Systems (MHPS) M501GAC G-Class turbines with an estimated 300 MW output each, and the same controls as proposed by AEC and permitted emissions limits of 2.0 ppmvd NO_X @ 15% O_2 and 26.91 lb/hr NO_X.
- The CPV St. Charles Power Station (Maryland) uses two GE F-Class turbines with an estimated 300 MW output each, and the same controls as proposed by AEC and permitted emissions limits of 2.0 ppmvd @ 15% O_2 NO_X and 21.7 lb/hr.
- The Hummel Station installed Siemen's 500F5ee F-Class turbines, with an estimated 300 MW output each, with the same controls as proposed by AEC and permitted emissions limits of 2.0 ppmvd NO_X @ 15% O_2 and 18.4 lb/hr NO_X.
- The New Covert Generating Facility is utilizing three MHPS M501G G-Class turbines with an estimated 400 MW output each, and the same controls as proposed by AEC and permitted emissions limits of 2.0 ppmvd NO_X @ 15% O_2 and 22.4 lb/hr NO_X.

The RBLC search for CT's operating without DB with lower limits than those proposed by AEC of 2.0 ppmvd NO_X @ 15% O_2 or 27.9 lb/hr NO_X indicated that the Filer City Station, with an estimated 250 MW output, is still being constructed and has not demonstrated their limits in practice, has a lower short-term hourly emission rate of 21.4 lb/hr NO_X. However, the unit has a lower heat input than the proposed AEC Project.

Combustion turbine emissions profiles are provided by the manufacturers, are project-specific, and are dependent on the CT vintage and class of equipment. Each CT project will have different site arrangements, stack parameters, fuels, operating scenarios, terrain effects, and emission profiles, combustion profiles, operating parameters, and efficiencies, resulting in varying emissions profiles that cannot be compared.

For example, the AEC project is proposing a single GE H-Class turbine. GE's H frame turbines have the largest gas turbine output and simplest design and are more efficient when compared to the older F frames, which may result in lower fuel costs from less fuel burn. The H-Class of turbine also has lower expected maintenance costs due to extended maintenance intervals and rotor life. Published data indicates that GE's H frame turbines may have a total cost of ownership that is lower than GE's F frame turbines[11]. Additionally, the efficient H frame turbines may result in a lower cost of electricity on the dispatch curve, and could have a more consistent operating profile, with fewer start-up and shutdown events[12]. Therefore, due to differences in fuel burn and efficiencies, turbines of a different frame will exhibit different emissions profiles that cannot be compared. A complete list of facilities with natural gas-fired CTs and HRSGs with DB from the RBLC is included in Table D-A-1. A complete list of facilities with natural gas-fired CTs and HRSGs without DB from the RBLC is included in Table D-A-2.

AEC proposes the use of good combustion practices, DLN combustors and SCR to achieve an emissions limit of 2.0 ppmvd @ 15% O_2 for the CT and HRSG with and without DB as NO_X LAER. Initial compliance will be demonstrated using U.S. EPA Method 7E and ongoing compliance will be monitored using a NO_X CEMS.

In addition to the non-steady-state NO_X limit proposed, Table 5-5 provides a summary of emissions limits during SU/SD events based on manufacturer data.

[11] What is the Future for Large Frame Gas Turbines? https://www.powerengineeringint.com/articles/print/volume-23/issue-2/talking-point/what-is-the-future-for-large-frame-gas-turbines.html
[12] The Fall of the F-Class Turbine https://www.power-eng.com/articles/print/volume-119/issue-8/features/the-fall-of-the-f-class-turbine.html

Table 5-5
Proposed NO_X LAER/BACT (Startup/Shutdown) for the CT and HRSG
Invenergy LLC – Allegheny Energy Center

Startup/Shutdown	Fuel	Peak Emissions (lb/event)
Cold Start	Natural Gas	250.0
Warm Start		180.0
Hot Start		90.0
Shutdown		14.0

5.3.2 BACT for CO

CO emissions occur as a result of incomplete combustion of carbon-based fuels. The primary factors influencing CO formation are temperature and residence time within the high temperature environment of the combustor. Variations in fuel carbon content have relatively little effect on overall CO emissions. Generally, the effect of the combustion zone temperature and residence time on CO emissions generation is the opposite of their effect on NO_X emissions generation. Higher combustion zone temperatures and residence times lead to more complete combustion and lower CO emissions, but higher NO_X emissions. The formation of CO emissions is also dependent on the loading of the turbine. A gas turbine operating under full load experiences greater fuel efficiency and reduces the formation of CO emissions. There are two basic techniques for controlling CO emissions from combustion units: good combustion practices and post-combustion controls – installation of oxidation catalysts in the HRSGs to oxidize CO to CO_2. Based upon a review of RBLC search results, existing permits for similar combined-cycle CTs, CT vendor information and technical literature, oxidation catalysts have been applied extensively over the last 10 years for CO control.

5.3.2.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling CO emissions from CTs and HRSG DBs. Maintaining optimum combustion efficiency and/or implementing appropriate maintenance procedures are examples of good combustion practices.

Oxidation Catalyst

Catalytic oxidation is an add-on control technology that is commonly used to reduce CO emissions. The catalysts are typically made of a precious metal and operate at temperatures in the range of 650°F to 1,000°F.[13] The catalysts cause excess O_2 to react with CO to form CO_2. However, an issue with catalytic oxidation is the catalyst's susceptibility to poisoning by fine particles in the exhaust gas, which reduces the catalyst's effectiveness. For combined-cycle units, the most effective location of the catalyst to minimize the impact of fine particles on the catalyst is prior to the HRSG and DB.

XONON™ Catalytic Combustor

The XONON™ catalytic combustor system is a NO_X control technology developed by Catalytica Energy Systems, Inc. that is also effective in CO control. XONON™ works by avoiding high temperatures caused by combustion. By integrating a catalyst into the combustor, XONON™ limits temperatures to below the level where NO_X is formed while still ensuring efficient combustion and low CO emissions. The XONON™ catalytic combustor system is a module that is installed inside the main component of the combustor. The module consists of a channel where pre-mixed fuel and air passes through the catalyst. The XONON™ catalytic combustor system

[13] Catalytic Oxidizer. *Technology Transfer Network Clearinghouse for Inventories & Emissions Factors.* http://cfpub.epa.gov/oarweb/mkb/contechnique.cfm?ControlID=10

eliminates the fuel being combusted in a flame by combusting the fuel using a catalyst at a lower temperature. The XONON™ catalytic combustor system is now owned by Kawasaki Heavy Industries, Ltd., which is in the process of making the control technology only available for gas turbine generators in the 1-1.4 megawatt (MW) range.

EMx™ Catalytic Absorption/Oxidation (Formerly SCONOX™)

EMx™ Catalytic Absorption/Oxidation is the second-generation of the SCONOX™ NO_X absorber technology that is distributed through EmeraChem. The EMx™ catalytic absorption/oxidation is a NO_X control technology that is also effective in CO control. This technology does not utilize ammonia and is able to achieve emissions less than 1 ppm NO_X, undetectable CO, near zero VOCs, and greater than 50% control of fine particulate matter[14]. Please refer to the previous description of this technology in Section 5.3.1.2.

5.3.2.2 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices are essential for the operation and life-span of the proposed CT and HRSG DB and will be used with the CT and HRSG DB. Therefore, good combustion practices are technically feasible for the CT and HRSG DB.

Oxidation Catalyst

Catalytic oxidation has been applied successfully on CTs and HRSG DBs similar to those proposed by AEC and is considered technically feasible. The CT and HRSG DB will include an oxidation catalyst as part of its design.

[14] http://emerachem.com/products/catalyst-coatings/adcat-catalyst-products

XONON™ Catalytic Combustor

Although developments to the XONON™ control technology are underway for gas turbines, such that it may become effective in gas turbine generators in the 1-1.4 MW range, this technology has not yet become available for application to larger turbine units similar to those proposed for the AEC Project. The current XONON™ catalytic combustor system has not been used on larger (i.e., greater than 1.4 MW)[15] combined-cycle turbines and therefore, it is not considered technically feasible.

EMx™ Catalytic Absorption/Oxidation (Formerly SCONOX™)

EMx™ is not considered technically feasible as discussed in Section 5.3.1.3.

5.3.2.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices and catalytic oxidation are both technically feasible and compatible technologies used for the control of CO. Catalytic oxidation is the most effective approach to controlling CO emissions because it is an add-on control technology capable of reducing CO emissions further than that of simply good combustion practices.

5.3.2.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices and catalytic oxidation will both be implemented as part of the design and operation of the CT and HRSG. Therefore, economic, environmental, and/or energy impacts were not assessed.

[15] Catalytic Combustion in Large Frame Industrial Gas Turbines. https://www.netl.doe.gov/File%20Library/Research/Coal/energy%20systems/turbines/handbook/3-2-2-2.pdf

5.3.2.5 Step 5 – Proposed BACT

AEC proposes to use good combustion practices and catalytic oxidation as CO BACT for the CT and HRSG to achieve the emissions limits presented in Table 5-6.

Table 5-6
Proposed CO BACT (steady-state) for the CT and HRSG
Invenergy LLC – Allegheny Energy Center

Emissions Unit	Fuel	BACT	Proposed Emissions Limit, 24-hour rolling	Short Term Limit Not to Exceed	Averaging Period
CT and HRSG DB firing	Natural Gas	Good combustion practices and catalytic oxidation	2.0 ppmvd @ 15% O_2	18.8 lb/hr	Three-hour rolling
CT and HRSG without DB firing	Natural Gas	Good combustion practices and catalytic oxidation	2.0 ppmvd @ 15% O_2	17.0 lb/hr	Three-hour rolling

To determine the appropriate proposed BACT limits, a search of the RBLC database and recently permitted facilities was conducted for similar CTs and HRSGs with and without DBs. The search revealed facilities with CO emissions limits for natural gas-fired CTs and HRSGs with and without DBs with permitted limits lower than AEC's proposed 2.0 ppmvd @ 15% O_2 limit, shown in Table 5-7. However, some facilities utilize CTs with a lower heat input and lower megawatt output, as well as a different CT model or manufacturer, which, as discussed in Section 5.1.3.1.6, will exhibit different emissions profiles than the unit proposed by AEC, and therefore, cannot be compared. A lower CO emissions rate with a higher NO_X emissions rate is the result of lower flame temperatures and lower combustion chamber temperatures that lower thermal NO_X formation. In addition, other units have yet to demonstrate that their listed emissions limit has been achieved in practice.

Table 5-7
CO BACT Determinations for the CT and HRSG
Invenergy LLC – Allegheny Energy Center

Emissions Unit	Project	Model/Make	Rated Output (MW)	Heat Input (MMBtu/hr)	Limit	Units	Determination
NG fired CT and HRSG DB	Tenaska PA Partners/ Westmoreland Gen Fac	Mitsubishi J Class	400 MW (1x1)	--	2	ppmvd @ 15% O2	Different manufacturer CT and HRSG
	Greensville Power Station	MHPS M501 J	1,588 MW	3,227 MMBtu/hr (3x1 w/ DB)	1.6	ppmvd @ 15% O2	Different manufacturer CT and HRSG
	Killingly Energy Center	Siemens SGT6-8000H	680 MW	CT: 2,639 MMBtu/hr DB: 946 MMBtu/hr	1.7	ppmvd @ 15% O2	Different manufacturer CT and HRSG
	Astoria Energy	GE 7421FA	575 MW (w/ DB)	--	1.5	ppmvd @ 15% O_2	Different model CT and HRSG
	Brunswick County Power Station	Mitsubishi M501 GAC	1,358 MW	3,442 MMBtu/hr (3x1 w/ DB)	1.5	ppmvd @ 15% O_2	Different manufacturer CT and HRSG
	Hummel Station	Siemens 5000F5	1,124 MW (3x1)	2,254 MMBtu/hr	1.9	ppmvd @ 15% O_2	Different manufacturer CT and HRSG
	Kleen Energy Systems	Siemens SGT6-5000F	580 MW, nominal, 2 CTs combined	CT: 2136 MMBtu/hr DB: 445 MMBtu/hr	0.9	ppmvd @ 15% O_2	Different manufacturer CT and HRSG
	Plant McDonough Combined Cycle	Mitsubishi J Class	254	--	1.8	ppmvd @ 15% O_2	Different manufacturer CT and HRSG
	West Deptford Energy Station	GE F or Siemens F	427 MW	CT = 2276 MMBtu/hr (HHV) DB = 777 MMBtu/hr(HHV)	1.5	ppmvd @ 15% O_2	Limit not demonstrated or achieved in practice
NG fired CT and HRSG without DB	Killingly Energy Center	Siemens SGT6-8000H	680 MW	CT: 2,639 MMBtu/hr	0.9	ppmvd @ 15% O2	Different manufacturer CT and HRSG
	Astoria Energy	GE 7241	1000 MW (w/ DB)	--	1.5	ppmvd @ 15% O_2	Different model CT and HRSG
	Avenal Energy Project	GE Frame 7FA	180 MW	--	1.5	ppmvd @ 15% O_2	Different model CT and HRSG
	Brunswick County Power Station	Mitsubishi M501 GAC	1,358 MW	--	1.5	ppmvd @ 15% O_2	Different manufacturer CT and HRSG
	Kleen Energy Systems	Siemens SGT6-5000F	580 MW, nominal, 2 CTs combined	CT: 2136 MMBtu/hr	0.9	ppmvd @ 15% O2	Different manufacturer CT and HRSG
	Palmdale Hybrid Power	GE Frame 7FA	650 MW	--	1.5	ppmvd @ 15% O_2	Limits achieved - Different, less efficient model
	Plant McDonough Combined Cycle	Mitsubishi J Class	6-254 MW CTs	--	1.8	ppmvd @ 15% O_2	Different manufacturer CT and HRSG
	Warren County Power Plant	Misubishi 501GAC	1,370 MW	2,996 MMBtu/hr	1.5	ppmvd @ 15% O_2	Different manufacturer CT and HRSG
	West Deptford Energy Station	GE F or Siemens F	427 MW	CT only: 2276 MMBtu/hr (HHV)	0.9	ppmvd @ 15% O_2	Limit not demonstrated or achieved in practice

Moreover, several air permits recently issued in Pennsylvania for combined-cycle power plants all specified CO BACT limits of 2.0 ppmvd @ 15% O_2. Therefore, the 2.0 ppmvd CO @ 15% O_2 limit based on a 24-hour averaging time is considered the most stringent CO limit achieved in practice for a large combined-cycle CT in Pennsylvania.

A complete list of facilities with natural gas-fired CTs and HRSG DBs from the RBLC is included in Appendix D Table D-A-3. A complete list of facilities with natural gas-fired CTs and HRSGs without DB from the RBLC is included in Table D-A-4.

During non-steady-state operations, AEC proposes the use of good combustion practices and an oxidation catalyst for the CT and HRSG to achieve an emissions limit of 2.0 CO ppmvd @ 15% O_2 when firing natural gas with and without DB as CO BACT. Initial stack testing to determine emission factors will be conducted using U.S. EPA Method 10 or equivalent. On-going compliance will be monitored using a CO continuous emission monitoring system (CEMS).

In addition to steady-state operating scenarios, AEC will also comply with CO limits during SU/SD. Table 5-8 provides a summary of proposed emissions limits during startup and shutdown events based on manufacturer data.

Table 5-8
Proposed CO BACT (Startup/Shutdown) for the CT and HRSG
Invenergy LLC – Allegheny Energy Center

Startup/Shutdown	Fuel	Peak Emissions (lb/event)
Cold Start	Natural Gas	900.0
Warm Start		570.0
Hot Start		390.0
Shutdown		85.0

5.3.3 **LAER for VOC**

The Project will be subject to LAER for VOC, because potential emissions of VOC from the Project will be greater than the 50 tpy major stationary source threshold applicable to O_3 precursor VOC emissions in the Northeast OTR. This section demonstrates that the proposed VOC emissions controls meet the requirements of LAER.

For CTs and HRSG DBs, VOC emissions occur as a result of incomplete combustion of carbon-based fuels. The primary factors influencing VOC formation are temperature and residence time within the high temperature environment of the combustor. Variations in fuel carbon content have relatively little effect on overall VOC emissions. Generally, the effect of the combustion zone temperature and residence time on VOC emissions generation is the exact opposite of combustion zone temperature and residence time effect on NO_X emissions generation. Higher combustion zone temperatures and residence times lead to more complete combustion and lower VOC emissions, but higher NO_X emissions. The formation of VOC emissions is also dependent on the loading of the turbine. A turbine operating under full load experiences greater fuel efficiencies than lesser loads and reduces the generation of VOC emissions. For purposes of this application, VOC will be expressed in terms methane (CH_4).

There are two basic techniques for controlling VOC emissions from combustion units: good combustion practices and post-combustion control which includes the installation of oxidation catalysts in the HRSGs to oxidize VOC to CO_2. Based upon a review of RBLC search results, existing permits for similar combined-cycle CTs, CT vendor information and technical literature, oxidation catalysts have been applied extensively over the last 10 years, primarily for CO control, but also for VOC control.

5.3.3.1 Identify the Most Stringent State Implementation Plan Limitation in Any State

The VOC control rules potentially applicable to natural gas-fired CTs and HRSG DBs were reviewed and summarized for the following states and/or AQMD in Table 5-9. These states and/or

AQMD comprise major ozone nonattainment areas in the U.S. Because CO is often used as a surrogate for VOC emissions, CO emissions limits were also searched for in the SIPs.

Table 5-9
VOC (or CO) SIP Limitations in Nonattainment States and AQMD for CTs and HRSGs with and without DBs
Invenergy LLC – Allegheny Energy Center

State or AQMD	Regulatory Limit	Citation
Bay Area AQMD, CA	No applicable VOC or CO limit.	BAAQMD Regulation 9
San Joaquin Valley Unified (SJVU) AQMD	VOC: No applicable VOC limit. CO: 200 ppmvd @ 15% O_2.	SJVUAQMD Rule 4703, Stationary Gas Turbines, Tier 2, enhanced limit
Texas Commission on Environmental Quality	VOC: No applicable VOC limit. CO: 132 ppmvd @ 15% O_2.	Chapter 117 – Control of Air Pollution from Nitrogen Compounds §117.1005
New Jersey Department of Environmental Protection	VOC: 50 ppmvd @ 15% O_2 CO: 250 ppmvd @ 15% O_2	New Jersey Administrative Code, Title 7:27-16.9
Massachusetts Department of Environmental Protection	VOC: No applicable VOC limit. CO: 50 ppmvd @ 15% O_2	310 CMR 7.19 – Reasonably Available Control Technology for Sources of Nitrogen Oxides
New York State Department of Environmental Conservation	No applicable VOC or CO limit.	6 NYCRR, Chapter III
Connecticut Department of Environmental Protection	No applicable VOC or CO limit.	RCSA 22a-174
Pennsylvania Department of Environmental Protection	No applicable VOC or CO limit.	Title 25 of the PA Code, Subpart C, Article III Air Resources

Table 5-9
VOC (or CO) SIP Limitations in Nonattainment States and AQMD for CTs and HRSGs with and without DBs
Invenergy LLC – Allegheny Energy Center

State or AQMD	Regulatory Limit	Citation
Florida Department of Environmental Protection	No applicable VOC or CO limit.	Chapter 62-296.570, F.A.C., Stationary Sources – Emission Standards
Georgia Department of Natural Resources, Environmental Protection Division	No applicable VOC or CO limit.	Chapter 391-3-1, Rule: .02 Provisions.
Illinois Environmental Protection Agency	VOC: No applicable VOC limit. CO: 200 ppm @ 50% O_2	Title 35, Illinois Administrative Code, Subtitle B, Chapter I, Subchapter C, Part 216.121 – Fuel Combustion Emission Sources

The most stringent VOC emissions limitation applicable to natural gas-fired CTs and HRSG DBs identified from this review of SIPs comprising ozone non-attainment areas was 50 ppmvd VOC @ 15% O_2. There are no NSPS that specify VOC limits for the CTs. The Project's proposed VOC emissions limits for the CTs and HRSGs with and without DB firing are more stringent than the most stringent SIP limitation found.

5.3.3.2 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling VOC emissions from a CT and HRSG DB. Maintaining optimum combustion efficiency and implementing appropriate maintenance procedures are examples of good combustion practices.

Oxidation Catalyst

Catalytic oxidation is an add-on control technology designed to decrease VOC emissions in conjunction with its target pollutant (i.e., CO). The catalysts are typically made of a precious metal and operate at temperatures in the range of 650°F to 1,000°F.[16] However, an issue with catalytic oxidation is the catalyst's susceptibility to poisoning by fine particles in the exhaust gas, which reduces the catalyst's effectiveness. For combined-cycle units, the most effective location of the catalyst to minimize the impact of fine particles on the catalyst is prior to the HRSG and DB.

XONON™ Catalytic Combustor

The XONON™ catalytic combustor system is a NO_X control technology developed by Catalytica Energy Systems, Inc. that may also be effective for VOC control. XONON™ works by avoiding high temperatures caused by combustion but still results in efficient combustion and effective VOC control. Please refer to the previous description of XONON™ in Section 5.3.1.2.

As noted previously, this technology is not currently available for larger turbines like those proposed for the CT and HRSG DB.

EMx™ Catalytic Absorption/Oxidation (Formerly SCONOX™)

EMx™ Catalytic Absorption/Oxidation is the second-generation of the SCONOX™ NO_X absorber technology that is distributed through EmeraChem. The EMx™ Catalytic Absorption/Oxidation is a NO_X control technology that is also effective in VOC control. This technology does not utilize ammonia and is able to achieve emissions less than 1 ppm NO_X,

[16] Catalytic Oxidizer. *Technology Transfer Network Clearinghouse for Inventories & Emissions Factors.* http://cfpub.epa.gov/oarweb/mkb/contechnique.cfm?ControlID=10

undetectable CO, near zero VOCs, and greater than 50% control of fine particulate matter[17]. Please refer to the previous description of this technology in Section 5.3.1.2.

5.3.3.3 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices are essential for the operation and life-span of the proposed CT and DB and will be used with the CT and HRSG DB. Therefore, good combustion practices are technically feasible for the CT and HRSG DB.

Oxidation Catalyst

Catalytic oxidation has been applied successfully on CTs and HRSG DBs similar to those proposed by AEC and is considered technically feasible. The CT and HRSG DB will include an oxidation catalyst as part of its design.

XONON™ Catalytic Combustor

The XONON™ control technology is limited to natural gas turbine generators in the 1-1.4 MW range. This technology has not yet become available for application to larger turbine units similar to those proposed for the AEC Project. Therefore, it is not considered technically feasible.

EMx™ Catalytic Absorption/Oxidation (Formerly SCONOX™)

EMx™ is not considered technically feasible as discussed in Section 5.3.1.3.

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[17] http://emerachem.com/products/catalyst-coatings/adcat-catalyst-products

5.3.3.4 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices and catalytic oxidation are technically feasible and compatible technologies used for the control of VOC. Catalytic oxidation is the most effective approach to controlling VOC emissions and is considered the top technology because it is an add-on control technology capable of reducing VOC emissions further than that of simply good combustion practices.

5.3.3.5 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Because VOC required a LAER analysis, the environmental, and/or energy impacts were not assessed in this LAER analysis.

5.3.3.6 Step 5 – Proposed LAER

AEC proposes to use good combustion practices and catalytic oxidation as VOC LAER for the CT and HRSG DB to achieve the emissions limits presented in Table 5-10.

Table 5-10
Proposed VOC LAER (steady-state) for the CT and HRSG
Invenergy LLC – Allegheny Energy Center

Emissions Unit	Fuel	Control Method	Proposed Emissions Limit (Average of three test runs)	Short Term Limit Not to Exceed	Averaging Period
CT and HRSG DB firing	Natural Gas	Catalytic oxidation and good combustion practices	1.5 ppmvd @ 15% O_2	8.1 lb/hr	Average of three test runs
CT and HRSG without DB firing	Natural Gas	Catalytic oxidation and good combustion practices	1.0 ppmvd @ 15% O_2	4.9 lb/hr	Average of three test runs

To determine the appropriate proposed LAER limits, a search of the RBLC database and recently permitted facilities was conducted for CTs and HRSGs with DBs. The RBLC and search of recently permitted facilities identified natural gas-fired CTs and HRSGs with DBs that had emission rates less than the proposed 1.5 ppmvd @ 15% O_2 limit for the natural gas-fired CT and HRSG DB. An additional RBLC search identified natural gas-fired CTs and HRSGs without DBs with emission rates less than the proposed 1.0 ppmvd @ 15% O_2 limit. Further research indicates that some facilities have limits that have not been achieved in practice, or use different makes and models of CTs, which exhibit different emissions profiles that are not directly comparable due to the CTs different size or different class of turbine or turbine manufacturer (i.e., GE F class turbines compared to GE H class turbines). As described in Section 5.3.1.6, CTs with smaller heat input will combust less fuel, and have lower emissions profiles, and are not comparable. A complete list of facilities with natural gas-fired CTs and HRSGs with DB from the RBLC is included in Appendix D Table D-A-5. A complete list of facilities with natural gas-fired CTs and HRSGs without DB from the RBLC is included in Table D-A-6.

AEC proposes VOC LAER as 1.5 ppmvd @ 15% O_2 when firing natural gas for the CT and HRSG DB, and 1.0 ppmvd @ 15% O_2 when firing natural gas for the CT and HRSG without DB. These limits will be achieved through the use of catalytic oxidation and good combustion practices. As the proposed VOC emissions limits are equivalent to the most stringent limits identified that are considered to be achieved in practice, they are sufficiently demonstrated as LAER for the combined-cycle CTs in this application.

To monitor compliance with VOC LAER, AEC will develop a correlation factor between CO and VOC emissions during an initial performance test by simultaneously operating CO CEMS while stack testing following U.S. EPA Reference Method 18, 25A. Using this correlation factor compliance with the CO limits will indicate compliance with the VOC limits. Stack testing will also be conducted every five years after the initial test to demonstrate compliance and verify the CO and VOC emissions correlation factor or to establish a new correlation factor if conditions have changed.

In addition to the steady-state limits mentioned, Table 5-11 provides a summary of emissions limits during SU/SD events based on manufacturer data.

Table 5-11
Proposed VOC LAER (Startup/Shutdown) for the CT and HRSG
Invenergy LLC – Allegheny Energy Center

Startup/Shutdown	Fuel	Peak Emissions (lb/hr)
Cold Start	Natural Gas	280.0
Warm Start		220.0
Hot Start		205.0
Shutdown		125.0

5.3.4 BACT for PM, PM_{10}, and $PM_{2.5}$

Emissions of PM, PM_{10}, and $PM_{2.5}$ from CTs and HRSGs with DBs are formed from carryover of noncombustible trace constituents in the fuel[18]. For the CT and HRSG with and without DB, emissions of $PM_{2.5}$ and PM_{10} include both the filterable and condensable portion of PM. Emissions of PM include the filterable portion only. The filterable portion of PM, PM_{10}, and $PM_{2.5}$ emissions is the result of noncombustible constituents in the fuel as well as incomplete combustion. The condensable portion of emissions is primarily the result of the formation of sulfates (e.g., H_2SO_4) and possibly organic compounds. The PM emitted from the turbines is conservatively assumed to be less than 2.5 microns in diameter. Therefore, PM_{10} and $PM_{2.5}$ emission rates are assumed to be the same.

[18] U.S. EPA AP-42, Stationary Gas Turbines. http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf

5.3.4.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a control technology for reducing PM, PM_{10}, and $PM_{2.5}$ emissions from CTs and HRSG DBs. The process is designed for high combustion efficiency, and the use of pipeline quality natural gas makes the particulate emissions inherently low. In addition, maintaining high combustion temperatures minimizes PM, PM_{10}, and $PM_{2.5}$ emissions that occur from incomplete combustion.

Low Sulfur Fuels

The formation of PM, PM_{10}, and $PM_{2.5}$ can be attributed to the oxidation of sulfur compounds, which precipitates as PM, PM_{10}, and $PM_{2.5}$ in the exhaust stream. Emissions can be lowered with the use of natural gas, which is inherently low in sulfur. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash.

Fabric Filter Baghouse

A fabric filter baghouse is a control technology used for reducing a portion of filterable PM, PM_{10}, and $PM_{2.5}$ from flue gas streams. The baghouse draws flue gas containing dust and condensables into filter tubes suspended in a housing unit. The PM, PM_{10}, and $PM_{2.5}$ builds up on the filter causing a buildup referred to as "cake" to form, which is removed periodically by pulsing, shaking, or reversing the air flow through the bags.

Electrostatic Precipitator

An electrostatic precipitator (ESP) is a control technology used to reduce PM, PM_{10}, and $PM_{2.5}$ emissions. It works by charging the particles of a flue gas stream with an electric field and then attracting them to electrically charged collector plates. The particles are then typically removed from the collection plates by means of mechanical rapping which causes the buildup to fall into hoppers.

Wet Electrostatic Precipitator

A wet electrostatic precipitator (WESP) is a PM, PM_{10}, and $PM_{2.5}$ control technology that operates by essentially the same process as an ESP. The difference between the technologies is that a WESP removes the particles from the collection plates by means of liquid washing rather than mechanical rapping.

Scrubber

A scrubber is a control technology used to reduce PM, PM_{10}, and $PM_{2.5}$ emissions by trapping suspended particles with liquid. Water or another liquid is sprayed into the dirty airstream so that it comes into contact with suspended particulate. Several configurations of scrubbers are currently used to control particulate, such as spray-tower scrubbers, orifice scrubbers, wet-impingement scrubbers, and venturi scrubbers. The most efficient configuration is the venturi scrubber, which has the highest relative velocity between the liquid droplets and the suspended particulate.

5.3.4.2 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices are essential for the operation and life-span of the proposed CT and HRSG and will be used with the CT and HRSG. Therefore, good combustion practices are technically feasible for the CT and HRSG.

Low Sulfur Fuels

Low sulfur fuels, such as natural gas, have been used successfully on combined-cycle CTs and HRSG DBs similar to the CT and HRSG DB proposed by AEC and are considered technically feasible. The CT and HRSG DB will include low sulfur fuels as part of its design.

Fabric Filter Baghouse, Electrostatic Precipitator, Wet Electrostatic Precipitator, and Scrubber

These add-on control technologies for reducing PM, PM_{10}, and $PM_{2.5}$ emissions are not technically feasible for use with combined-cycle CTs and HRSG DBs due to high operating temperatures during the combustion process and the CT and HRSG DB's inherently low PM, PM_{10}, and $PM_{2.5}$ emissions. Additionally, according to the RBLC database, these control technologies have not been utilized on combined-cycle CTs and HRSG DBs. Therefore, these technologies will not be considered further in this analysis.

5.3.4.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices, including the use of low sulfur fuels, are the only remaining technologies; therefore, a ranking is not necessary.

5.3.4.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices, including the use of low sulfur fuels, will be implemented as part of the design and operation of the CT and HRSG DB. Therefore, economic, environmental, and/or energy impacts were not assessed.

5.3.4.5 Step 5 – Proposed BACT

Particulate Matter

AEC proposes good combustion practices, including the use of low sulfur fuels, as PM, PM_{10}, and $PM_{2.5}$ BACT for the CT and HRSG to achieve the emissions limits presented in Table 5-12.

Table 5-12
Proposed PM BACT (steady-state) for the CT and HRSG
Invenergy LLC – Allegheny Energy Center

Emissions Unit	Fuel	BACT	Proposed Emissions Limit	Short Term Limit Not to Exceed	Averaging Period
CT and HRSG DB firing	Natural Gas	Good combustion practices and low sulfur fuel	0.0029 lb/MMBtu	10.6 lb/hr	Average of three (3) stack test runs
CT and HRSG without DB firing	Natural Gas	Good combustion practices and low sulfur fuel	0.0042 lb/MMBtu	8.2 lb/hr	Average of three (3) stack test runs

To derive the proposed BACT limits for the natural gas-fired CT and HRSG with and without DB, a search of the RBLC database and recently permitted facilities was conducted for similar CTs and HRSG DBs. This search identified several facilities that had permitted emission rates lower than the proposed 0.0029 lb/MMBtu and equivalent 10.6 lb/hr PM emissions limit for the proposed natural gas-fired CT and HRSG DB and lower than the proposed 0.0042 lb/MMBtu and equivalent 8.2 lb/hr PM emissions limit for the proposed natural gas-fired CT and HRSG without DB. Several facilities use CTs with a significantly lower heat input and power output and different CT makes and models, which exhibit different emissions profiles that are not directly comparable. In addition, several facilities (MEC North, LLC, MEC South, LLC, Filer City Station, and Middlesex Energy Center) are still being constructed and thus have not demonstrated their limits in practice. Several facilities (Okeechobee Clean Energy Center and Dania Beach Energy Center) have proposed higher natural gas fuel sulfur contents [i.e., 2 grains of sulfur per 100 standard cubic feet (gr S/100 SCF) of natural gas then the 0.4 gr S/100 SCF limit proposed by AEC], thus the limits cannot be compared.

Table 5-13
PM BACT Determinations for the CT and HRSG
Invenergy LLC – Allegheny Energy Center

Emissions Unit	Project	Model/Make	Rated Output (MW)	Heat Input (MMBtu/hr)	Limit	Units	Determination
NG fired CT and HRSG DB	MEC North, LLC and South, LLC	H Class Turbine	500 MW	3,080 MMBtu/hr (HHV)	5.8	lb/hr	Limit not demonstrated or achieved in practice
	INDECK NILES, LLC	--	500 MW	CT: 3,421 MMBtu/hr DB: 740 MMBtu/hr	9.9	lb/hr	Limit not demonstrated or achieved in practice
	Blythe Energy Project II	Siemens SGT6-5000F	170 MW	--	6.0	lb/hr	Different manufacturer CT and HRSG, 0.5 gr/100 scf
	Cheyenne Prairie Generating Station	GE LM6000 PF Sprint	40 MW	--	4.0	lb/hr	Different model CT and HRSG
	Gateway Cogeneration 1	Rolls Royce Trent 60 WLE	168 MW	--	5.0	lb/hr	Different manufacturer CT and HRSG
	GenConn Middletown	GE LM6000PC	4 @ 50 MW each	475 MMBtu/hr	6.0	lb/hr	Different model CT and HRSG
	Sabine Pass LNG Terminal	GE LM2500+G4, Combined Cycle Refrigeration Compressor Turbines (8)	--	289 MMBtu/hr	2.08	lb/hr	Different model CT and HRSG
NG fired CT and HRSG without DB	Okeechobee Clean Energy Center	GE 7HA.02	3x1 Total 1,600 MW	3,069 MMBtu/hr, each	2	Gr. S/100 SCF	Higher sulfur content in fuel
	Dania Beach Energy Center	GE 7HA	2 x 1 430 MW each	4,000 MMBtu/hr, each	2	Gr. S/100 SCF	Higher sulfur content in fuel
	Filer City Station	--	~250 MW	1,934.7 MMBtu/hr	0.0025	lb/MMBtu	Limit not demonstrated or achieved in practice
	Middlesex Energy Center	GE 7HA.02	380 MW	3,462 MMBtu/hr	4.4	lb/hr	Limit not demonstrated or achieved in practice
	Cheyenne Prairie Generating Station	GE LM6000 PF Sprint	40 MW	--	4.0	lb/hr	Different model CT and HRSG
	Gateway Cogeneration 1	Rolls Royce Trent 60 WLE	168 MW	--	5.0	lb/hr	Different manufacturer CT and HRSG
	Pueblo Airport Generating Station	GE LM6000 PF Sprint	--	373 MMBtu/hr	4.3	lb/hr	Different model CT and HRSG
	Sabine Pass LNG Terminal	GE LM2500+G4, Combined Cycle Refrigeration Compressor Turbines (8)	--	289 MMBtu/hr	2.08	lb/hr	Different model CT and HRSG
	Westlake Vinyls Company LP Cogeneration Plant	GE LM6000 PF Sprint	--		3.72	lb/hr	Different model CT and HRSG

A complete list of facilities with natural gas-fired CTs and HRSGs with DB from the RBLC is included in Table D-A-7. A complete list of facilities with natural gas-fired CTs and HRSGs without DB from the RBLC is included in Table D-A-8.

PM_{10}/$PM_{2.5}$

AEC proposes good combustion practices, including the use of low sulfur fuels, as PM_{10}/$PM_{2.5}$ BACT for the CT and HRSG. Table 5-14 presents the proposed emissions limits using these controls to be achieved for PM_{10}/$PM_{2.5}$ during steady-state operation.

Table 5-14
Proposed PM_{10}/$PM_{2.5}$ BACT (steady-state) for the CT and HRSG
Invenergy LLC – Allegheny Energy Center

Emissions Unit	Fuel	BACT	Proposed Emissions Limit	Short Term Limit Not to Exceed	Averaging Period
CT and HRSG DB firing	Natural Gas	Good combustion practices and low sulfur fuel	0.0058 lb/MMBtu	21.1 lb/hr	Average of three (3) stack test runs
CT and HRSG without DB firing	Natural Gas	Good combustion practices and low sulfur fuel	0.0084 lb/MMBtu	16.5 lb/hr	Average of three (3) stack test runs

To determine the proposed BACT limits for the natural gas-fired CT and HRSG with and without DB, a search of the RBLC database and recently permitted facilities was conducted for similar CTs and HRSGs. The search identified units with emissions rates less than the proposed limit for the natural gas-fired CT and HRSG with and without DB. Some facilities have limits that have not been achieved in practice. In addition, other facilities use different makes and models of CTs, which exhibit different emissions profiles that are not directly comparable due to the CTs different size or different class of turbine or turbine manufacturer (i.e., GE F class turbines compared to GE H class turbines). As described in Section 5.3.1.6, CTs with smaller heat input will combust less fuel, and have lower emissions profiles, and are not comparable. A complete list of facilities with natural gas-fired CTs and HRSGs with DB from the RBLC is included in Table D-A-9 and Table D-A-11. A complete list of facilities with natural gas-fired CTs and HRSGs without DB from the RBLC is included in Table D-A-10 and Table D-A-12.

$PM/PM_{10}/PM_{2.5}$

It should also be noted that $PM/PM_{10}/PM_{2.5}$ emissions during startup and shutdown are equivalent to or less than those during steady-state operation. An initial stack test to determine emission factors will be conducted using Method 5 or equivalent for PM and using Methods 201/201A/202 or equivalent for $PM_{10}/PM_{2.5}$. On-going compliance will be demonstrated using fuel throughput and emissions factors developed during the initial stack tests, and through the use of fuel supplier sulfur content certifications.

5.3.5 **BACT for SO_2**

SO_2 results from the oxidation of fuel sulfur. SO_2 is formed when sulfur contained in the fuel is burned, combining with O_2 in the combustion air to create SO_2.

5.3.5.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling SO_2 emissions from a CT and HRSG DB. Maintaining optimum combustion efficiency or implementing appropriate maintenance procedures are examples of good combustion practices.

Scrubber/Flue Gas Desulfurization

A scrubber (or desulfurization unit) is a control technology used to control SO_2 emissions. Scrubbers (wet or dry) use chemical and mechanical processes to remove SO_2 from the exhaust gas. However, according to a search of recently permitted facilities and the RBLC database, there are currently no CTs and HRSG DBs that employ this technology. As such, scrubbers are not considered available for these sources.

5.3.5.2 Step 2 – Eliminate Technically Infeasible Options

Good combustion practices, including the use of low sulfur fuels, are essential for the operation and life-span of the proposed CT and HRSG. Therefore, good combustion practices are technically feasible for the CT and HRSG.

5.3.5.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices and low sulfur fuels are the only available technologies used for the control of SO_2. Therefore, a ranking is not necessary to establish the top technology.

5.3.5.4 Step 4 – Evaluate Economic, Environmental and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices and low sulfur fuels will be implemented as part of the design and operation of the CT and HRSG; therefore, economic, environmental, and/or energy impacts were not assessed.

5.3.5.5 Step 5 – Proposed BACT

AEC proposes to use good combustion practices, including the use of low sulfur fuels, as SO_2 BACT for the CT and HRSG with and without DB to achieve the emissions limits presented in Table 5-15. Emissions limits for SO_2 will be the same during all modes of operation (i.e., steady-state, startup, and shutdown operations).

Table 5-15
Proposed SO_2 BACT for the CT and HRSG
Invenergy LLC – Allegheny Energy Center

Emissions Unit	Fuel	BACT	Proposed Emissions Limit	Short Term Limit Not to Exceed	Averaging Period
CT and HRSG DB	Natural Gas	Good combustion practices and low sulfur fuel	0.0014 lb/MMBtu	5.6 lb/hr	Average of three (3) stack test runs
CT and HRSG without DB	Natural Gas	Good combustion practices and low sulfur fuel	0.0014 lb/MMBtu	5.1 lb/hr	Average of three (3) stack test runs

To determine the appropriate proposed BACT limits, a search of the RBLC database and recently permitted facilities was conducted for similar CTs and HRSGs. The search identified units with SO_2 emissions rates for a natural gas-fired CT and HRSG with and without DB less than the proposed 0.0014 lb/MMBtu limits. Some facilities have limits that have not been achieved in practice. In addition, other facilities use different makes and models of CTs, which exhibit different emissions profiles that are not directly comparable due to the CTs different size or different class of turbine or turbine manufacturer (i.e., GE F class turbines compared to GE H class turbines. As described in Section 5.3.1.6, CTs with smaller heat input will combust less fuel, and have lower emissions profiles, and are not comparable. Several facilities identify lower lb/hr emissions limits but utilize natural gas with fuel sulfur content greater than the 0.4 gr S/100 SCF proposed by AEC.

A complete list of facilities with natural gas-fired CTs and HRSGs with DB from the RBLC is included in Table D-A-13. A complete list of facilities with natural gas-fired CTs and HRSGs without DB from the RBLC is included in Table D-A-14.

Therefore, AEC proposes that the use of good combustion practices, including the use of low sulfur fuels and specifically the use of pipeline natural gas, to achieve an emissions limit of 0.0014 lb/MMBtu with and without DB. Initial stack testing to determine emission factors will be conducted using U.S. EPA Method 8 or equivalent. On-going compliance will be demonstrated using emission factors developed during initial stack testing, monitoring actual fuel throughput rates, and through the use of fuel supplier certified sulfur content fuel.

5.3.6 BACT for H_2SO_4

H_2SO_4 emissions result from the oxidation of sulfur in fuel as well as the oxidation of SO_2 by the DBs and catalysts used for NO_X, CO, and VOC control. H_2SO_4 is formed when SO_2 is oxidized into sulfur trioxide (SO_3) and the SO_3 combines with water vapor to form H_2SO_4. While there are no post-combustion control technologies available for H_2SO_4 emissions associated with a CT, a top-down BACT analysis for H_2SO_4 was performed for completeness purposes.

5.3.6.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling H_2SO_4 emissions from the CT and HRSG. Good combustion practices include the use of low sulfur fuels (e.g., natural gas), as well as maintaining optimum combustion efficiency and implementing appropriate maintenance procedures. Fuel treatment technologies are applied to gaseous, liquid, and solid fuels to reduce their sulfur contents prior to delivery to the end user. The fuel proposed for the Project combined-cycle units is pipeline-quality natural gas only. Desulfurization of natural gas is performed by the fuel supplier prior to distribution by pipeline. The sulfur content of pipeline quality natural gas is typically less than 2.0 gr S/100 SCF or less. Based on specifications obtained from the gas supplier, AEC is proposing a natural gas sulfur limit of 0.4 gr S/100 SCF.

Flue Gas Desulfurization

Flue Gas Desulfurization (FGD) systems (or scrubbers) are post-combustion control technologies that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas. The chemical reaction with an alkaline chemical, which can be performed in a wet or dry contact system, converts the SO_2 to sulfite or sulfate salts. By reducing the amount of SO_2, the FGD system would ultimately reduce the amount of H_2SO_4 that could be formed.

5.3.6.2 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices, including the use of low sulfur fuels, are essential for the operation and life-span of the proposed CT and HRSG DB, and will be used with this CT and HRSG DB. Therefore, good combustion practices are technically feasible.

Flue Gas Desulfurization

AEC is proposing to fire natural gas which contains only trace amounts of sulfur. The removal efficiency of a wet or dry FGD system reduces with decreasing inlet SO_2 concentration levels. FGD technology has been shown to function efficiently on emissions streams with relatively high uncontrolled SO_2 levels (e.g., boilers firing high-sulfur coal). However, the SO_2 emissions from the proposed CT are two orders of magnitude lower than emissions rates typically achievable using FGD for high-sulfur fuels. According to a 2013 PSD determination in Washington (October 21, 2013), "SO_2 concentrations in flue gases from natural gas combustion are too low for a FGD to work effectively, be technologically feasible, or cost-effective."[19] Moreover, according to another PSD determination in Virginia (March 2013), "FGD is only feasible on plants that produce larger quantities of SO_2 and H_2SO_4 and would produce a significant pressure drop that would require an induced draft fan, potentially causing air/fuel mixing problems."[20] Therefore, FGD is technically infeasible for the CT and HRSG.

[19]Technical Support Document for PSD Permit. Permit No: PSD-11-05. Pg. 23 of 110. http://www.ecy.wa.gov/programs/air/psd/PSD_PDFS/PSE_Fredonia_TSD_PSD-11-05_10212013.pdf.

[20]Engineering Analysis: Virginia Electric and Power Company - Brunswick Plant. http://www.deq.virginia.gov/Portals/0/DEQ/Air/Permitting/PSDPermits/52404_analysis.pdf.

5.3.6.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices and low sulfur fuels are technically feasible and compatible control technologies for H_2SO_4. Therefore, a ranking has not been considered to establish a top technology.

5.3.6.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices and low sulfur fuels will be implemented as part of the design and operation of the CT and HRSG. Therefore economic, environmental, and/or energy impacts were not assessed.

5.3.6.5 Step 5 – Proposed BACT

AEC proposes to use good combustion practices, including the use of low sulfur fuels, as H_2SO_4 BACT for the CT and HRSG with and without DB to achieve the emissions limits presented in Table 5-16. Emissions limits for H_2SO_4 will differ based on whether duct-firing is on, but will be the same during steady-state, startup, and shutdown operations.

Table 5-16
Proposed H_2SO_4 BACT for the CT and HRSG
Invenergy LLC – Allegheny Energy Center

Emissions Unit	Fuel	BACT	Proposed Emissions Limit	Short Term Limit Not to Exceed	Averaging Period
CT and HRSG DB	Natural Gas	Good combustion practices and low sulfur fuels	0.00100 lb/MMBtu	4.0 lb/hr	Average of three (3) stack test runs
CT and HRSG without DB	Natural Gas	Good combustion practices and low sulfur fuels	0.00101 lb/MMBtu	3.6 lb/hr	Average of three (3) stack test runs

To determine the appropriate proposed BACT limits, a search of the RBLC database and other recently permitted facilities was conducted for similar CTs and HRSGs. Recent sulfur contents range from 0.2 to 2 gr S/100 SCF and H_2SO_4 emission factors range from 0.0001 to 0.004 lb/MMBtu. The search identified several units with H_2SO_4 emissions rates for a natural gas-fired CT and HRSG with and without DB that are less than the proposed 0.00100 lb/MMBtu and 0.00101 lb/MMBtu emission limits, respectively.

Some facilities have limits that have not been achieved in practice. In addition, other facilities use different makes and models of CTs, which exhibit different emissions profiles that are not directly comparable due to the CTs different size or different class of turbine or turbine manufacturer (i.e., GE F class turbines compared to GE H class turbines. As described in Section 5.3.1.6, CTs with smaller heat input will combust less fuel, and have lower emissions profiles, and are not comparable. Several facilities identify lower lb/hr emissions limits but utilize natural gas with fuel sulfur content greater than the 0.4 gr S/100 SCF proposed by AEC. A complete list of facilities with natural gas-fired CTs and HRSGs with DBs from the RBLC search is included in Table D-A-15. A complete list of facilities with natural gas-fired CTs and HRSGs without DB from the RBLC is included in Table D-A-16.

AEC proposes that the use of good combustion practices and low sulfur fuels, specifically the use of pipeline-quality natural gas with fuel sulfur content of 0.4 gr S/SCF, as sufficiently demonstrated BACT for the proposed CTs to achieve an emissions limit of 0.00100 lb/MMBtu with DB and a limit of 0.00101 lb/MMBtu without DB. Initial stack testing to determine emission factors will be conducted using U.S. EPA Method 8 or equivalent. On-going compliance will be demonstrated using emission factors developed during initial stack testing, monitoring actual fuel throughput rates, and through the use of fuel supplier certified sulfur content fuel.

5.3.7 BACT for GHG

Although there are six regulated GHGs: CO_2, CH_4, nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6),[21] GHG emissions emitted from stationary combustion sources typically consist of CO_2, CH_4, and N_2O. Emissions of GHG pollutants are converted to a carbon dioxide equivalent (CO_2e) basis using their individual global warming potentials (GWPs)[22] for comparative purposes. CO_2 and N_2O are produced in the CT and HRSG when firing natural gas. The carbon in the fuel is converted to CO_2 during combustion. N_2O formation is complex and depends on many factors, but it can be limited when combustion temperatures are kept high (i.e., above 1,475°F, which is expected for a CT and HRSG) and excess air is kept low (i.e., below 1%). Emissions of CH_4 are likely caused by unburned fuel when firing natural gas. CH_4 emissions are highest during conditions of low-temperature combustion or incomplete combustion. Such conditions typically occur during the startup or shut down cycle for turbines.

The proposed CT and HRSG DB will have a DLN combustor system and SCR for NO_X emissions reduction and an oxidation catalyst for control of CO and VOC. Installation of the SCR system may increase emissions of N_2O as a result of exhaust conditions and the type of catalyst selected. However, these emissions would be negligible in regard to the overall GHG emissions from the Project. Likewise, the installation of the oxidation catalyst may slightly increase emissions of CO_2 from the oxidation of CO and CH_4 in the flue gas. While slight increases in CO_2 may occur from the oxidation catalyst, these emissions are accounted for in the total GHG emissions (i.e., CH_4 and CO_2 are both components of total GHGs). Use of SCR and oxidation catalyst will also slightly decrease the Project thermal efficiency due to backpressure on the CT. Although elimination of these controls could conceivably be considered as an option within the GHG BACT, the environmental benefits of controlling NO_X, CO, and VOC emissions are assumed to outweigh the

[21] U.S. EPA Greenhouse Gas Emission Reductions. http://www2.epa.gov/greeningepa/greenhouse-gases-epa
[22] U.S. EPA Glossary of Climate Change Terms. http://www.epa.gov/climatechange/glossary.html

marginal increase to GHG emissions. Therefore, omission of these controls within the BACT analysis was not considered.

5.3.7.1 Step 1 – Identify Available Control Technologies

A search was conducted of recently permitted facilities and the RBLC database which can be found in Appendix D Table D-A-17.

An effort was made to review the U.S. EPA GHG Mitigation Options Database (G-MOD) as part of the BACT analysis for the CT and HRSG DB. However, this database currently is not maintained by U.S. EPA and access was not available as of the date of this submittal.

There are no currently-applicable NSPS or state rules that would establish a baseline GHG emission rate for the combined-cycle CTs for the Project. However, NSPS Subpart TTTT would limit CO_2 emissions from new combustion turbines with design heat inputs to the turbine greater than 250 MW (850 MMBtu/hr) to 1,000 pounds CO_2/MWh of electricity generated on a gross basis on a 12-operating month rolling average.

Based on this review, the following technologies were identified as available control technologies for GHG emissions:

- Energy efficient and inherently lower-emitting processes/work practices/design
- Good combustion practices
- Add-on controls
    - Carbon capture and sequestration [CCS]
    - Oxidation catalyst
    - thermal oxidation

Energy Efficient and Inherently Lower-Emitting Processes/Work Practices/Design

U.S. EPA, through various guidance documents, indicates that inherently lower-polluting processes are appropriate for consideration as available control alternatives. In guidance documents, U.S. EPA recommends several different ways to incorporate energy efficiency (good combustion practices) into a project including, but not limited to: installing an efficient CT and

HRSG, employing a maintenance program, or using low-carbon fuels. The following are examples of inherently lower-emitting processes, work practices and design:

- Use of CT with the latest design to maximize fuel energy to electrical generation
- Maximizing the heat recovery in the HRSG surface area for heat recovery
- Flue gas oxygen monitoring
- Insulation

The CT and HRSG chosen are highly efficient. Based on manufacturer's website information, the GE H Class model has a combined-cycle efficiency of more than 63%[23]. These highly efficient combined-cycle operations compare to older simple-cycle units with thermal efficiencies as low as 42%[24]. The implementation of a maintenance program for the CT and HRSG will not only retain the energy efficiency of the unit, but also help assure minimized GHG emissions. Maintenance programs may include the following:

- **Periodic Maintenance and Tuning** – Follow manufacturer recommendations regarding inspection and maintenance activities to maintain/restore optimal efficiency.
- **Reduce Heat Losses** – Install insulation on both the ST and HRSG components and dampers in the HRSG stack to minimize heat loss thereby increasing energy efficiency via heat recovery.
- **Instrumentation and Controls** – Employ the use of the latest computer-based control systems to monitor and optimize fuel and air flows. This optimizes combustion operations thereby producing the maximum amount of power for the least amount of fuel burned while maintaining emissions performance over a range of load and ambient temperature conditions.
- **Steam Cycle Efficiency** – Employ a reheat steam cycle to increase the amount of power generated from the recovered waste heat.
- **Heat Exchanger Design** – Select a design which optimizes waste heat transfer from the CT exhaust gas while minimizing corrosion at the outlet of the HRSG.
- **Minimize Fouling of Heat Exchanger Surfaces** – Employ inlet air filtering, proper feed water chemistry, and tube surface cleaning practices. This minimizes fouling of the heat exchanger surfaces and maintains the maximum waste heat exchange between the CT exhaust gas and the HRSG thereby maintaining/restoring optimal efficiency.

[23] GE 7HA.01/7HA.02 Gas Turbine. https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/product/gas%20turbines/Fact%20Sheet/2017-prod-specs/7ha-power-plants.pdf
[24] GE Gas Turbine Evolution 7HA.01/.02 Gas Turbine. https://powergen.gepower.com/products/heavy-duty-gas-turbines/7ha-gas-turbine.html

- **Reduce Steam Losses** – Follow an inspection routine that checks for and repairs steam leaks from valves, flanges, and piping to maintain/restore optimal efficiency.

The proposed CT and HRSG DB will use natural gas, which is one of the fuels with the lowest carbon content. Having a lower carbon content fuel means that there is less carbon available to convert to CO and CO_2 during combustion, inherently reducing GHG emissions.

Good Combustion Practices

Good combustion practices for combined-cycle CTs fired with natural gas include the following:

- Good air/fuel mixing in the combustion zone
- Sufficient residence time to complete combustion
- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality
- Good burner maintenance and operation practices
- High temperatures and low oxygen levels in the primary combustion zone
- Overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency

As with other types of fossil fuel-fired systems, combustion control is the most effective means for reducing CH_4 emissions. Combustion controls combined with good combustion practices and minimization of time spent in non-steady state operations minimize uncombusted hydrocarbon (CH_4). Combustion efficiency is related to the three "T's" of combustion: Time, Temperature, and Turbulence. These components of combustion efficiency are designed into the combined-cycle CTs to maximize fuel efficiency and reduce operating costs. Therefore, combustion control is accomplished primarily through unit design and operation.

Carbon Capture and Sequestration

For the purposes of a BACT analysis for GHGs, U.S. EPA classifies CCS as an add-on pollution control technology that is “available” for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams.[25] According to U.S. EPA, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs.[26] This section provides an overview of CCS technology for reference.

CCS has been applied commercially in the oil and gas industry for several decades. This includes technologies such as solvent-based separation of CO_2 from gas streams, transportation of CO_2 by pipeline and storage of CO_2 in aquifers. CO_2 can also be used for enhanced oil recovery (EOR). While CCS has been applied in the oil and gas industry, CCS is still an emerging technology in the power sector, where it has not yet been demonstrated on a large scale. Applying CCS to full-size power plants requires scale-up of commercially available CO_2 captures processes. Therefore, current cost and performance information related to CCS from power generation needs to be evaluated.

CCS is an approach used to capture the CO_2 emissions from facilities, where CO_2 is then stored. Capture technologies include pre-combustion carbon capture and post-combustion carbon capture. Pre-combustion carbon capture for combustion sources involves substituting pure oxygen for air in the combustion process, resulting in a concentrated CO_2 exhaust stream so it may be captured more effectively. The oxygen may be isolated from air using a number of technologies, including cryogenic separation and membrane separation. Post-combustion carbon capture for combustion sources is applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO_2 from the combustion exhaust gases. Post-combustion capture using solvent scrubbing, typically using monoethanolamine (MEA) as the solvent, is a commercially mature technology.[27] There are a number of methods and processes that could be used to capture CO_2 from the dilute exhaust gases produced by new combustion units. These capture technologies include separation with solvent or physical filters, cryogenic separation to condense the CO_2, and

[25] United States Environmental Protection Agency. PSD and Title V Permitting Guidance for Greenhouse Gases. http://www3.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf
[26] United States Environmental Protection Agency. PSD and Title V Permitting Guidance for Greenhouse Gases. http://www3.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf
[27] United States Environmental Protection Agency. Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry. October 2010. http://www3.epa.gov/nsr/ghgdocs/refineries.pdf

membrane separation technologies. In general, CCS technology comprises the following distinct stages:

- Separation of CO_2 from the exhaust gases (CO_2 capture)
- Pressurization of the captured CO_2
- Transmission of CO_2 via pipeline
- Injection and long-term storage of the captured CO_2

In order to provide effective reduction of CO_2 emissions, efficient methods of compression, transport, and storage are required. This requires transporting the CO_2 to a suitable geological storage formation such as:

- Depleted oil and gas reservoirs
- Unmineable coal seams
- Saline formations
- Basalt formations
- Terrestrial ecosystems

For large projects, off-site CO_2 sequestration generally relies upon a third-party CO_2 pipeline system in order to transport the CO_2. Pipelines are the most common and theoretically feasible method for transporting large quantities of CO_2. Constructing such a pipeline for dedicated use by a single facility often will make a project economically infeasible. However, such an option may be effective if both adequate storage capacities exist in close proximity to the source, and reasonable transportation prices can be arranged with the pipeline operator.[28] In addition, there are unresolved issues with respect to CO_2 sequestration including the legal process for closing and remediating sequestration sites and liability for accidental releases from these sites.

U.S. EPA estimates CCS can reduce GHG emissions from power plants by approximately 80 to 90%.[29] For the purposes of this BACT analysis, AEC assumes that the implementation of CCS can achieve 90% reduction.

[28] Air Products, Application for an Air Permit for the Delaware City Hydrogen Facility Project, April 2012. https://delaware.sierraclub.org/sites/delaware.sierraclub.org/files/documents/2012/05/air_products_hydrogen_facility.pdf

[29] United States Environmental Protection Agency, Carbon Dioxide Capture and Sequestration at http://www.epa.gov/climatechange/ccs/ and Center for Climate and Energy Solutions, Carbon Capture and Storage Quick Facts. http://www.c2es.org/technology/factsheet/CCS

Oxidation Catalysts

Oxidation catalysts have been applied as a control technology for CO and VOC emissions from sources such as natural gas-fired combined-cycle gas turbines[30]. Since CH_4 is a hydrocarbon, it is expected that oxidation catalysts would also provide reduction in CH_4 emissions. Oxidation catalysts use excess air that is present in the combustion exhaust, along with the activation energy necessary for the reaction to occur in the presence of a catalyst across a temperature range of approximately 850°F to 1,100°F to reduce CH_4 concentrations.

Based on a review of various vendor websites, a typical VOC control efficiency of an oxidation catalyst ranges between 15 to 50%. This control efficiency is assumed to be representative and achievable for CH_4 for the purposes of this BACT analysis.

Thermal Oxidation

There are several types of thermal oxidation technologies. All of these technologies oxidize CH_4 to CO_2 and H_2O, by raising the temperature of the exhaust stream to approximately 1,600ºF for approximately one to two seconds. Given sufficient mixing and residence time at this temperature thermal oxidation is capable of achieving at least a 98% reduction in CH_4 emissions.

5.3.7.2 Step 2 – Eliminate Technically Infeasible Options

Energy Efficient and Inherently Lower-Emitting Processes/Work Practices/Design

The energy efficient and inherently lower-emitting processes, work practices, and design as described in previous section will, be implemented as part of the CT and HRSG; therefore, they are considered technically feasible for the CT and HRSG DB for potential CO_2 (GHG) control.

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[30] FEDR, February 2013.

Carbon Capture and Sequestration

Although CCS is not considered commercially available for use on CTs and HRSGs, it has been considered technically feasible, as required by U.S. EPA Guidance for this evaluation for potential CO_2 (GHG) control.

Oxidation Catalysts

Oxidation catalysts have been applied as a control technology for CO and VOC emissions from natural gas-fired combined-cycle gas turbines and would also provide reduction in CH_4 emissions. The CT and HRSG DB design already includes an oxidation catalyst and, therefore, is considered technically feasible for the CT and HRSG DB for potential CO_2 (GHG) control.

Thermal Oxidation

In order for CH_4 to reach its oxidation point, additional heat would need to be added to the CT and HRSG DB. To gain this additional heat, additional fuel would need to be fired. Additional fuel would produce additional CO_2 emissions, thereby reducing the overall effectiveness in reducing CO_2e emissions from this control technology. In addition, secondary pollutants are produced by thermal oxidation. These include NO_X and CO from the combustion of natural gas used to heat the process stream. While thermal oxidation may be considered technically feasible for the CT and HRSG DB, because the additional fuel required to raise the temperature of the exhaust stream would increase the emissions from this unit, thermal oxidation was not considered practical for the CT and HRSG DB. Therefore, thermal oxidation is not included for consideration further in this BACT analysis.

5.3.7.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The third step in the top-down GHG BACT review process ranks the remaining control technologies by control effectiveness. The potential control technologies for the CT and HRSG DB were ranked for effectiveness based on readily available information obtained from the sources consulted for this BACT analysis. The percent reduction values are the estimated percent reductions of CO_2e from the baseline emission rate.

1. CCS: 80-90%
2. Oxidation Catalyst: 60-80%
3. Energy Efficiency: 10-50%

5.3.7.4 Step 4 - Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

As previously mentioned, in order to provide effective reduction of CO_2 emissions via CCS, efficient methods of compression, transport, and storage are required. In addition, there are unresolved issues with respect to CO_2 sequestration including the legal process for closing and remediating sequestration sites and liability for accidental releases from these sites. Creating the infrastructure to allow for the compression, transport and storage of CO_2 emissions would far exceed the cost of the installation of CCS. While CCS may be theoretically feasible in reducing atmospheric emissions of CO_2 after formation, without this necessary transportation and sequestration infrastructure, CCS is too difficult and costly to be practical.

CCS requires a complex pipeline infrastructure. Because a pre-existing pipeline infrastructure is not in close proximity to the Project, installing a pipeline to accommodate an injection site near the Project is considered impractical. The effort required to construct miles of pipeline through regions in the eastern U.S., in addition to uncertainties associated with acquiring land access needed for pipeline construction, is considered impractical for the Project. Also, pipeline transportation requires very high pressures with high compressor energy requirements and requires H_2O to be removed from CO_2 pipelines. The CO_2 pipeline infrastructure requires routine monitoring for leaks, and protection from overpressure, especially in highly populated areas. Therefore, CCS is not considered available for the Project. Furthermore, the combined-cycle power plant incremental capital costs associated with the CCS equipment needed for CO_2 capture, compression, and pipeline transportation would be approximately $1.33 billion[31]. This level of control cost would constitute an adverse economic impact and is not cost effective for the proposed Project.

Given project-wide GHG emissions, the cost of CCS would be approximately $123/ton[31], which is above the range of cost effectiveness values considered to be reasonable and acceptable in BACT determinations. Contributing factors to cost ineffectiveness include proximity to a demonstrated and available CO_2 storage project, existing pipeline infrastructure, and post combustion capture and compression costs. For example:

- A 2012 report, "Analysis of the Costs and Benefits of CO_2 Sequestration on the U.S. Outer Continental Shelf" estimates that sequestration costs are in the $10-30/ton range.[32]
- A 2011 report entitled "Cost and Performance of Carbon Dioxide Capture from Power Generation" by the International Energy Agency (IEA) estimates where CCS has sufficient infrastructure to be developed, the cost for CO_2 capture would be between $60 and $128/ton, with an average of about $80/ton CO_2 avoided.[33]
- In making the GHG BACT determination for Copano Processing, U.S. EPA determined that control of GHG emissions at a cost of $54/ton is not BACT because it is "economically prohibitive."[34]
- In making the GHG BACT determination for the City of Palmdale, U.S. EPA determined that control of GHG emissions at a cost of $45/ton is not BACT because it is "economically infeasible."[35]
- In making the GHG BACT determination for Valero's McKee Refinery, located in Texas, U.S. EPA determined that control of GHG emissions at a cost effectiveness of $134/ton is not BACT.[36]

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31 Based on representative values listed in IPCC Special Report on Carbon Dioxide Capture and Storage, Chapter 3: Capture of CO2, Table 3.15, (http://www.ipcc.ch/pdf/special-reports/srccs/srccs_chapter3.pdf).

32 Vidas, Harry, Hungman, Bob, Chikkatur, Ananth, and Boddu Venkatesh. Analysis of the Costs and Benefits of CO2 Sequestration on the U.S. Outer Continental Shelf.

33 Finkenrath, Matthias. Cost and Performance of Carbon Dioxide Capture from Power Generation

34 Statement of Basis: Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Copano Processing, L.P., Houston Central Gas Plant, Permit Number: PSD-TX-104949- GHG. U.S. EPA Region 6, December 2012. (Cost effectiveness calculated based on listed cost of $10.9 million/yr for annual emission reduction of 202,000 tons per year.)

35 Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Project. U.S. EPA Region 9, October 2011. (Cost effectiveness calculated based on listed cost of $78 million/yr for annual emission reduction of 1.7 million tons per year.)

36 *Statement of Basis: Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Diamond Shamrock Refining Company, L.P., Valero McKee Refinery Permit Number: PSD-TX-861-GHG*, July 2013, p. 7; and *Diamond Shamrock Refining Company, L.P., a*

Utilizing the identified feasible control technologies for GHG BACT for the CT and HRSG, AEC will meet the limit presented in Table 5-17. The heat rate limit was provided by GE with a compliance margin of 5% that accounts for the equipment as constructed and installed.

Table 5-17
Proposed GHG BACT for the CT and HRSG
Invenergy LLC – Allegheny Energy Center

Emissions Unit	Fuel	BACT	Proposed Emissions Limit	Emissions Limits Units
CT and HRSG	Natural Gas	Oxidation catalyst in conjunction with implementing energy efficient and using inherently lower-emitting processes, work practices, combustion practices, and design	6,468	Btu/kWh, full load
			749	lb CO_2e/MWh
			340	kg CO_2e/MWh
Facility-Wide	N/A		1,950,023	tpy CO_2

To determine the emissions limits, a search of recently permitted facilities and a search of the RBLC database was conducted. A summary can be found in Appendix D Table A-1-18. The results of the search confirmed that the proposed GHG emissions limits on a Btu/kWh for the CT and HRSG when firing natural gas are lower than recently permitted facilities and entries in the RBLC.

Compliance with GHG emissions on an efficiency basis (i.e., Btu/kWh), will be based on an annual thermal efficiency test according to American Society of Mechanical Engineers (ASME) Performance Test Code (PTC)-46 (or other approved method) conducted on natural gas at base load with DB firing. Compliance with the GHG limit (lb CO_2e/MWh, kg CO_2e/MWh) is determined through stack testing to develop an emissions factor. This emissions factor is then multiplied by the fuel usage and divided by the net power generation of the facility.

Annual emissions from the CTs will be included in an annual Facility-wide GHG (in CO_2e) limit to be calculated on a 12-month rolling period. The annual Facility-wide GHG limit is referenced

- In making the GHG BACT determination for Freeport LNG Development, L.P.'s Freeport LNG Liquefaction Project, U.S. EPA determined that control of GHG emissions from the amine treatment units was cost prohibitive, where the cost effectiveness of the control option under consideration was estimated at approximately \$14/ton of CO_2 sequestered.[37]

5.3.7.5 Step 5 – Proposed BACT

Based on Steps 1 through 4 of the top-down BACT analysis presented in this narrative, AEC proposes the use of oxidation catalyst in conjunction with implementing energy efficient and inherently lower-emitting processes, work practices, and design. These may include the following:

CT energy efficiency design, practices, and procedures:

- Efficient turbine design
- Periodic turbine burner tuning
- Reduction in heat loss (i.e., insulation of the CT)
- Instrumentation and controls

HRSG energy efficiency design, practices, and procedures:

- Efficient heat exchanger design
- Reduction in heat loss, (i.e., insulation of HRSG)
- Minimizing steam venting and repair of steam leaks

Plant-wide energy efficiency design, practices, and procedures:

- Fuel gas preheating
- Drain operation
- Maximizing HRSG design to allow for the most efficient combination of CT and ST design
- Inherently monitoring flue gas in the design of the unit to minimize excess oxygen within safety limits in order to maximize thermal efficiency
- Addition of extra insulation of the CT combustion section and HRSG compared to older designs will minimize heat losses, thereby reducing fuel input and in turn reduce GHG emissions

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Valero Company Greenhouse Gas Prevention of Significant Deterioration Permit Application for Crude Expansion Project Valero McKee Refinery Sunray, Texas, Updated December 2012, p. 4-15.

[37] *Statement of Basis: Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Freeport LNG Development, L.P., Freeport LNG Liquefaction Project, Permit Number: PSD-TX-1302-GHG,* December 2013, p. 31; and Greenhouse Gas PSD Application, Freeport LNG Development, L.P., December 2011, p. 10-21.

in Table 5-17. These emissions will be inclusive of the CT and HRSG with and without DB, auxiliary boiler, dew point heater, emergency generator, fire water pump, circuit breakers, and piping components based on the following calculation methods. Initial compliance for the CT and HRSG DB will be based on a performance test for CO_2 using U.S. EPA Method 3A or equivalent. On-going compliance for the CT and HRSG DB will be demonstrated using fuel throughput and emissions factors developed during annual stack tests. Circuit breaker GHG emissions will be calculated based on the amount of SF_6 used and assuming a 0.5% leakage rate. Piping component GHG emissions will be calculated based on actual number of piping components, emission factors from 40 CFR 98, Table W-1A, and 97.6% methane content by volume.

5.4 CONTROL TECHNOLOGY ANALYSIS FOR THE AUXILIARY BOILER

This section presents the BACT and LAER determination process for the auxiliary boiler for CO, PM, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4, and GHG and NO_X and VOC, respectively.

The processes by which pollutants are formed from combustion in an auxiliary boiler mirror those occurring in a CT and HRSG. As such, several similar available control technologies can be applied to both the CT and HRSG as well as the auxiliary boiler. Table 5-18 presents the proposed LAER/BACT limits with corresponding control technologies for the auxiliary boiler.

Table 5-18
Proposed LAER/BACT for the Auxiliary Boiler
Invenergy LLC – Allegheny Energy Center

Pollutant[a]	BACT	Fuel	Proposed Emissions Limit	Emissions Limit Units	Averaging Period
NO_X	Good combustion practices, ULNB and FGR	Natural Gas	0.011	lb/MMBtu	Average of three test runs
			0.98	lb/hr	
CO	Good combustion practices and limited operation	Natural Gas	0.04	lb/MMBtu	Average of three test runs
			3.62	lb/hr	
VOC	Good combustion practices	Natural Gas	0.004	lb/MMBtu	Average of three test runs
			0.35	lb/hr	
PM	Good combustion practices and low sulfur fuels	Natural Gas	0.00181	lb/MMBtu	Average of three test runs
			0.16	lb/hr	
$PM_{2.5}$/ PM_{10}	Good combustion practices and low sulfur fuels	Natural Gas	0.00149	lb/MMBtu	Average of three test runs
			0.1318	lb/hr	
SO_2	Good combustion practices and low sulfur fuels	Natural Gas	0.0011	lb/MMBtu	Average of three test runs
			0.10	lb/hr	
H_2SO_4	Good combustion practices and low sulfur fuels	Natural Gas	0.000135	lb/MMBtu	Average of three test runs
			0.01	lb/hr	
GHG	Energy efficient design and work practices	Natural Gas	Will comply with Facility-wide GHG emissions limit.		

(a) Emission limits of $PM_{2.5}$/PM_{10} are inclusive of the condensable portion and filterable portion of particulate, while the emission limit of PM represents the filterable portion only based on U.S. EPA's Emission Inventory and Analysis Group guidance 3/30/2012 with 3x safety factor.

5.4.1 LAER for NO

The Project will be subject to LAER for NO_X, because estimated potential emissions of NOx will be greater than the 100 tpy Major Stationary Source threshold applicable to an O_3 precursor in the Northeast OTR. NO_X emissions from the Project are also subject to PSD review, including BACT requirements. This section demonstrates that the proposed NO_X emissions and controls meet the requirements of LAER. Because LAER requirements are at least as stringent as BACT, the LAER analysis also satisfies the BACT demonstration for NO_X.

NO_X is primarily formed by two mechanisms: the combination of elemental N_2 and O_2 in the combustion air within the high temperature environment of the combustor (thermal NO_X); and the oxidation of N_2 contained in the fuel (fuel NO_X). When firing natural gas, NO_X emissions from auxiliary boiler originate primarily as thermal NO_X. The rate of formation of thermal NO_X is a function of residence time and free O_2 and is exponential with peak flame temperature.

5.4.1.1 Identification of Most Stringent State Implementation Plan Limitation in Any State

As part of a LAER analysis the most stringent emissions limitations that are contained in the SIP of any State for such class or category of stationary sources were identified. States that contain the most severe ozone nonattainment areas typically contain the most stringent NO_X limits in their SIPs. Therefore, the NO_X control rules potentially applicable to auxiliary boilers fired with natural gas were reviewed and summarized for the following states and/or AQMD in Table 5-19.

Table 5-19
NO_X Auxiliary Boiler SIP Limitations in Other Nonattainment States
Invenergy LLC – Allegheny Energy Center

State/AQMD	Regulatory Limit	Citation
Bay Area AQMD, CA	5 ppmvd @ 3 % O_2 (0.006 lb/MMBtu) for natural gas-fired boiler, steam generator or process heater > 75 MMBtu/hr;	BAAQMD Regulation 9, Rule 9, 9-7-307.6

Table 5-19
NO_X Auxiliary Boiler SIP Limitations in Other Nonattainment States
Invenergy LLC – Allegheny Energy Center

State/AQMD	Regulatory Limit	Citation
San Joaquin Valley Unified (SJVU) AQMD	9 ppmvd @ 3 percent O_2 (0.011 lb/MMBtu) for natural gas-fired boiler, steam generator or process heater > 20 MMBtu/hr; 15 ppmvd @ 3 percent O_2 (0.018 lb/MMBtu) for natural gas-fired boiler, steam generator or process heater <20 MMBtu/hr	SJVUAQMD Rule 4306, Boilers, steam generators and process heaters – phase 2
Texas Commission on Environmental Quality (TCEQ)	0.10 lb/MMBtu for gas-fired boilers >40 MMBtu/hr	30 TAC Part 1, Chapter 117 – Control of Air Pollution from Nitrogen Compounds §117
New Jersey Department of Environmental Protection	0.1 lb/MMBtu for natural gas-fired boiler or process heater at least 50 MMBtu/hr but less than 100 MMBtu/hr	New Jersey Administrative Code, Title 7:27-19.7, Table 8
Massachusetts Department of Environmental Protection	0.2 lb/MMBtu for boilers burning only gas	310 CMR 7.19 – Reasonably Available Control Technology for Sources of Nitrogen Oxides
New York State Department of Environmental Conservation	0.05 lb/MMBtu for mid-sized natural gas-fired boilers (i.e., greater than 25 MMBtu/hr but less than 100 MMBtu/hr)	6NYCRR, Chapter III, Part 227-2.4(c): Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_x)
Connecticut Department of Environmental Protection	0.20 lb/MMBtu for natural gas-fired boiler	RCSA 22a-174-22 Control of Nitrogen Oxides Emissions

The most stringent NO_X emissions limitation applicable to the auxiliary boiler identified from this review of SIPs comprising the most severe ozone nonattainment areas is 5 ppmvd NO_X @ 3 percent O_2. As noted in Appendix 5.1C of Northern California Power Agency's (NCPA's)

Application for Certification (AFC) submittal for the Lodi Energy Center Project (LEC), the SJVAPCD's BACT determination for boilers similar to the proposed auxiliary boiler with variable loads show that 9 ppm is considered technically feasible[38]. The BAAQMD has determined 7 ppm, or lower is considered technologically feasible; however, the BAAQMD BACT guideline recognizes that SCR is needed to achieve 7 ppm [or lower][39]. A more recent determination completed by the Sacramento Cogeneration Authority on March 5, 2015 (Application No. A/C 24398 & 24399) reaffirm that achieving an emissions rate of 5 ppm NO_X requires the use of SCR[40]. As discussed in this section, SCR is not feasible for control of the auxiliary boiler, thus the proposed NO_X emissions limit for the boiler is 0.01 lb/MMBtu for LAER/BACT.

5.4.1.2 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling NO_X emissions from an auxiliary boiler. Maintaining optimum combustion efficiency or implementing appropriate maintenance procedures are examples of good combustion practices.

Selective Catalytic Reduction

SCR is a control technology used to convert NO_X into diatomic N_2 and H_2O using a catalyst. The reduction reactions used by SCR require O_2, so it is most effective at O_2 levels above 2-3%. SCR can achieve a NO_X reduction rate in the range of 70 - 90%.[41] Base metals, such as vanadium or titanium, are often used for the catalyst due to their effectiveness as a control technology for NO_X and cost-effectiveness for use with natural gas combustion. In addition, a gaseous reductant such

[38] *Lodi Energy Center-Application for Certification, Supplement D: Changes to Equipment and Project Fenceline*. Submitted to the California Energy Commission (7/2009), (Page 5.1C.16).
[39] Ibid.
[40] *Sacramento Cogeneration Authority-Authority to Construct Evaluation*. Application No. A/C 24398 & 24399. (3/5/15), (Page 5).
[41] EPA (U.S. Environmental Protection Agency). 2003. "Selective Catalytic Reduction Air Pollution Control Technology Fact Sheet." *EPA-452/F-03-032*

as $NH_{3(aq)}$ is added to the flue gas and absorbed onto the catalyst.[42] The problems associated with the catalysts used for SCR include the lack of high thermal durability of the base metals and their potential to oxidize SO_2 into SO_3.

Selective Non-Catalytic Reduction

SNCR is a post-combustion control technology for NO_X emissions that uses a reduction-oxidation reaction to convert NO_X into N_2, H_2O, and CO_2. Like SCR, SNCR involves injecting ammonia (or urea) into the flue gas stream, which must be between approximately 1,400 and 2,000°F for the chemical reaction to occur.

NO_X reduction levels range from 30 - 50%, but if SNCR is applied in conjunction with combustion controls, such as low NO_X burners, reductions of 65 - 75% can be achieved.[43] However, operating constraints on temperature, reaction time, and mixing often lead to less effective results when using SNCR in practice.

Low-NO_X Burners

The use of LNB is an example of a front-end control technology for limiting NO_X emissions from an auxiliary boiler. LNB delay combustion by staging the air or fuel in multiple zones and thus limit peak flame temperatures. This results in uniform temperatures below the peak NO_X formation temperature range thereby lowering NO_X emissions.

Ultra-Low-NO_X Burners

Similar to LNB, ULNB is another example of a front-end control technology for limiting NO_X emissions from an auxiliary boiler. While ULNB limit peak flame temperature by separating

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[42] The U.S. Department of Energy and Southern Company Services, Inc., "Control of Nitrogen Oxide Emissions: Selective Catalytic Reduction (SCR)"

[43] EPA (U.S. Environmental Protection Agency). 2003. "Selective Non-Catalytic Reduction Air Pollution Control Technology Fact Sheet." *EPA-452/F-03-031*

combustion into multiple stages, ULNB use more advanced techniques, such as internal FGR and lean premixing of the air and fuel, to reduce NO_X emissions to negligible levels.

Flue Gas Recirculation

FGR is a control technology used for limiting emissions of NO_X from a boiler. The technology works by returning up to 25% of the flue gas from a burner back to the combustion chamber. This can be done with hot gas fans and combustion air duct mixing devices (known as forced FGR) or via induced FGR, which routes flue gas through ducts directly into the existing forced draft fan inlet. The flue gas absorbs heat from the flame, lowering the peak flame temperature and reducing NO_X formation. The flue gas also mixes with the combustion air and lowers the oxygen content of the air, thereby limiting the NO_X-forming reaction. This simple and effective control technology is part of the heating process design.

5.4.1.3 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices, including the use of low sulfur fuels, are essential for the operation and life-span of the proposed auxiliary boiler, and will be used with this auxiliary boiler. Therefore, good combustion practices are technically feasible.

Selective Catalytic Reduction/Selective Non-Catalytic Reduction

The auxiliary boiler will be used on an as-needed basis during periods of shutdown and to provide sealing steam to the steam turbine during warm and hot starts. SCR emissions control technology is not considered technically feasible for the proposed auxiliary boiler because the design effectiveness of an SCR is not achieved until the flue gas temperature reaches between 400 and 800°F. The proposed auxiliary boiler will be required to supply steam in an expedited manner to minimize the duration of the combined cycle unit start-up. The combined cycle unit start-up produces elevated pollutant emissions concentrations during each start-up procedure. This same reason applies for the application of SNCR control for the auxiliary boiler, thus both SCR and SNCR are deemed technically infeasible.

Low-NO_X Burners

The use of LNB has been found to be technically feasible for use in auxiliary boilers, and therefore is considered further in the evaluation.

Ultra-Low-NO_X Burners

The use of ULNB has been found to be technically feasible for use in auxiliary boilers, and therefore is considered further in the evaluation.

Flue Gas Recirculation

FGR has been found to be technically feasible for use in auxiliary boilers, and therefore is considered further in the evaluation.

5.4.1.4 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The remaining control technologies are good combustion practices, LNB, ULNB, and FGR. AEC can reach its limit through the use of good combustion practices, ULNB, and FGR.

5.4.1.5 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

AEC proposes to use good combustion practices, ULNB, and FGR as NO_X LAER/BACT. Therefore, economic, environmental, and/or energy impacts were not assessed in this LAER/BACT analysis.

5.4.1.6 Step 5 – Proposed LAER/BACT

AEC proposes to use good combustion practices, ULNB, and FGR as LAER/BACT for the auxiliary boiler and has a proposed fuel-firing limit of 337.9 MMSCF of natural gas per year. A review was conducted of NO_X LAER determinations for auxiliary boilers, including a search of the RBLC database and a review of information concerning recently permitted facilities with auxiliary boilers. Two facilities (Moxie Freedom Generation Plant and Lackawanna Energy Center) were identified with a lower limit of 0.006 lb/MMBtu for NO_X. Moxie Freedom Generation Plant utilizes a boiler much smaller in size (55.4 MMBtu/hr) when compared to the auxiliary boiler proposed by AEC. Since combustion efficiency is related to the three "T's" of combustion -- time, temperature, and turbulence -- boilers of different sizes, makes, and manufacturer's technology may allow for different combustion profiles. The remaining facility, Lackawanna Energy Center, has demonstrated their limit of 0.006 lb/MMBtu in practice, however the implementation of SCR for this unit has led to additional unnecessary operating time and fuel usage in order to sustain compliance. Thus, their limit does not have to be considered.

A complete list of facilities with natural gas-fired auxiliary boilers from the RBLC is included in Table D-B-1.

As such, AEC proposes good combustion practices, the use of ULNB and FGR as LAER and BACT to control NO_X emissions from the proposed auxiliary boiler to achieve a NO_X emissions limit of 0.01 lb/MMBtu.

5.4.2 **BACT for CO**

This section presents the CO BACT discussion for the auxiliary boiler. The rate of CO emissions from a boiler depends on the efficiency of the natural gas combustion. Improperly tuned boilers and boilers operating at off-design levels decrease combustion efficiency, which results in increased CO emissions.[44]

5.4.2.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling CO emissions from the auxiliary boiler. Maintaining optimum combustion efficiency and/or implementing appropriate maintenance procedures are examples of good combustion practices.

Oxidation Catalyst

Catalytic oxidation is an add-on control technology designed to reduce CO emissions. The catalysts are typically made of a precious metal and operate at temperatures in the range of 650°F to 1,000°F.[45] The catalysts cause excess O_2 to react with CO to form CO_2.

Thermal Oxidation

Thermal oxidation is also an add-on control technology designed to reduce CO emissions. Thermal oxidation reduces CO emissions by supplying sufficient O_2 at temperatures of at least 1,400 to 1,500°F,[46] thus combusting CO into CO_2 and water.

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[44] U.S. EPA AP-42. Chapter 1.4. Natural Gas Combustion http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf
[45] Catalytic Oxidizer. *Technology Transfer Network Clearinghouse for Inventories & Emissions Factors.* http://cfpub.epa.gov/oarweb/mkb/contechnique.cfm?ControlID=10
[46] EPA (U.S. Environmental Protection Agency). 2003. "Regenerative Incinerator Air Pollution Control Technology Fact Sheet." *EPA-452/F-03-021*

5.4.2.2 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices, including the use of low sulfur fuels, are essential for the operation and life-span of the proposed auxiliary boiler. Therefore, good combustion practices are technically feasible, and will be used with this auxiliary boiler.

Oxidation Catalyst

Although an oxidation catalyst has been used to reduce CO and VOC emissions from boilers, it is not considered technically feasible to use it with the auxiliary boiler because the auxiliary boiler is required to supply steam quickly to the combined cycle units during the startup procedure and the oxidation catalyst requires a high flue gas temperature to achieve effective control. A more effective method of reducing emissions, including CO, is by good combustion controls and restricting operation on an annual basis. AEC is able to achieve the most stringent emission limit through the use of good combustion practices and has proposed a fuel-firing limit of 337.9 MMSCF of natural gas per year.

Thermal Oxidation

Thermal oxidation reduces CO emissions by supplying sufficient oxygen at temperatures of at least 1,400 to 1,500°F. Since the exhaust gas temperature of the proposed auxiliary boiler is significantly lower than the temperature that is required, a supplementary-fired burner would be needed to achieve the operating temperature of a thermal oxidation system. Because the combustion of the fuel for an oxidation system would itself result in CO emissions, it is presumed that thermal oxidation would result in minimal overall CO emission reductions. Furthermore, no applications of thermal oxidation were demonstrated for a natural gas-fired boiler in a review of the RBLC database. Therefore, while thermal oxidation as a CO control technology may be considered technically feasible, it is not an "available" CO control option for the proposed auxiliary boiler and is not considered further.

5.4.2.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices are a technically feasible and compatible technology used for the control of CO and, therefore, a ranking has not been considered to establish a top technology.

5.4.2.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices will be implemented as part of the design and operation of the auxiliary boiler. Therefore, economic, environmental, and/or energy impacts were not assessed.

5.4.2.5 Step 5 – Proposed BACT

AEC proposes to use good combustion practices as CO BACT for the auxiliary boiler. To determine the appropriate proposed BACT limits, a search of the RBLC database and other recently permitted facilities was conducted for similar auxiliary boilers. Several facilities which have lower auxiliary boiler CO emissions limits were identified.

Auxiliary boilers are constructed by different manufacturers and for different purposes and can exhibit different emission rates. If an auxiliary boiler is designed specifically to meet a lower CO threshold, the unit's NO_X emissions will be higher. AEC has identified several facilities (Harrah's Operation Company, Inc., Nucor Steel – Berkeley, Nucor Steel – Arkansas, and Texstar Gas Process Facility) that have CO emissions limits lower than the proposed auxiliary boiler. However, these facilities have auxiliary boilers with NO_X emissions significantly higher than the proposed auxiliary boiler's NO_X emissions, which are achieved through lower flame temperatures and lower combustion chamber temperatures that lower thermal NO_X formation. Thus, the CO emissions limits for the auxiliary boilers at the identified facilities cannot be directly compared to the CO emissions limits of the proposed auxiliary boiler because of the influence of the NO_X emissions limits.

Some facilities (Woodbridge Energy Center, Oregon Clean Energy Center, ThyssenKrupp Steel and Stainless USA, LLC, Flopam Inc., Hess Newark Energy Center, Cheyenne Prairie Generating

Station, Toledo Supplier Park – Paint Shop, and Sunbury Generation LP) have a lower lb/hr or tpy emissions limit, but also have an equivalent or higher lb/MMBtu emissions limit than what is proposed by AEC. Because the resulting CO mass emissions rates from an auxiliary boiler are based on applying a performance based BACT lb/MMBtu emissions limit, the CO limits for those facilities do not have a more stringent emissions limit than what is proposed for the auxiliary boiler.

Several facilities (Middlesex Energy Center LLC, Harrison County Power Plant, Hickory Run Energy Center, Kalama Energy Center, Pioneer Valley Energy Center, and Moundsville Combined Cycle Power Plant) have lower proposed CO emissions limits; however, they have yet to be built, and therefore have not demonstrated their emissions limit in practice.

Several facilities (Astoria Energy LLC, MGM Mirage, PSEG Fossil LLC Sewaren Generating Station, CPV St. Charles, Wildcat Point Generation Facility, and Berks Hollow Energy Association LLC) have a CO emissions limit which is more stringent when compared to the 0.04 lb/MMBtu emissions limit proposed by AEC. However, these facilities are using the same control technologies as those proposed by AEC, and therefore the difference in emissions limits can be attributed to manufacturer differences. Additionally, Astoria Energy LLC was required to meet LAER, which is not comparable to BACT.

A complete list of facilities with natural gas-fired auxiliary boilers from the RBLC is included in Table D-B-2.

AEC proposes good combustion practices as BACT for the auxiliary boiler in order to meet the proposed CO emissions limit of 0.04 lb/MMBtu.

5.4.3 LAER for VOC

The Project will be subject to LAER for VOC, because estimated potential emissions of VOC from the Project will be greater than the 50 tpy Major Stationary Source threshold applicable to O_3 precursor VOC emissions in the Northeast OTR. VOC emissions from the Project are also subject to PSD review, including BACT requirements. This section demonstrates that the proposed VOC emissions and controls meet the requirements of LAER. Because LAER requirements are at least as stringent as BACT, the LAER analysis also satisfies the BACT demonstration for VOC.

VOC emissions occur as a result of incomplete combustion of hydrocarbons in fuel. AEC has evaluated the control of VOC emissions from the proposed auxiliary boiler in order to determine LAER/BACT.

5.4.3.1 Identify the Most Stringent State Implementation Plan Limitation in Any State

The VOC control rules potentially applicable to auxiliary boilers fired with natural gas were reviewed and summarized for the following states and/or AQMD in Table 5-20.

Table 5-20
VOC Auxiliary Boiler SIP Limitations in Other Nonattainment States
Invenergy LLC – Allegheny Energy Center

State/AQMD	Regulatory Limit	Citation
Bay Area AQMD, CA	No applicable VOC limit.	BAAQMD Regulation 9
San Joaquin Valley Unified (SJVU) AQMD	No applicable VOC limit.	SJVUAQMD Rule 4320, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr
Texas Commission on Environmental Quality	No applicable VOC limit.	Chapter 115 – Control of Air Pollution from Volatile Organic Compound Sources
New Jersey Department of Environmental Protection	VOC: 50 ppmvd @ 7 % O_2 (i.e., 0.078 lb/MMBtu) for boilers greater than 50 MMBtu/hr	New Jersey Administrative Code, Title 7:27-16.8 – Boilers
Massachusetts Department of Environmental Protection	No applicable VOC limit.	310 CMR 7.00

Table 5-20
VOC Auxiliary Boiler SIP Limitations in Other Nonattainment States
Invenergy LLC – Allegheny Energy Center

State/AQMD	Regulatory Limit	Citation
New York State Department of Environmental Conservation	**No applicable VOC limit.**	6NYCRR, Chapter III
Connecticut Department of Environmental Protection	No applicable VOC limit.	RCSA 22a-174
Pennsylvania Department of Environmental Protection	No applicable VOC limit.	Title 25 of the Pa. Code, Subpart C, Article III Air Resources
Florida Department of Environmental Protection	No applicable VOC limit.	Chapter 62-296.570, F.A.C., Stationary Sources – Emission Standards
Georgia Department of Natural Resources, Environmental Protection Division	No applicable VOC limit.	Chapter 391-3-1, Rule: .02 Provisions.
Illinois Environmental Protection Agency	No applicable VOC limit.	Title 35, Illinois Administrative Code

The most stringent VOC emissions limitation applicable to the auxiliary boiler identified from this review of SIPs comprising the most severe ozone nonattainment areas was 50 ppmvd @ 7% O_2 for VOC. There are no NSPS that specify VOC limits for the auxiliary boiler. The Project's proposed VOC emissions limit, 0.004 lb/MMBtu, for the auxiliary boiler is more stringent than the most stringent SIP limitation found.

5.4.3.2 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling VOC emissions from the auxiliary boiler. Maintaining optimum combustion efficiency, and/or implementing appropriate maintenance procedures, are examples of good combustion practices.

Oxidation Catalyst

Catalytic oxidation is an add-on control technology designed to reduce VOC emissions. The catalysts are usually made of a precious metal and they operate at temperatures in the range of 205 to 260°F.[47] The catalyst causes excess O_2 to react with VOCs to form CO_2. However, an issue with catalytic oxidation is the catalyst's susceptibility to poisoning by fine particles in the exhaust gas, which reduces the catalyst's effectiveness.

Flue Gas Recirculation

FGR has been used to control both NO_X and VOC emissions. This technology allows the combustion process to occur with less excess air and without increasing the combustion chamber temperature, which results in minimizing VOC emissions.

Thermal Oxidation

Thermal oxidation reduces VOC emissions by supplying sufficient oxygen at temperatures of at least 1,400 to 1,500°F. Because the exhaust gas temperature of the proposed auxiliary boiler is significantly lower than the temperature that is required, a supplementary-fired burner would be needed to achieve the operating temperature of a thermal oxidation system. Since the combustion of the fuel for an oxidation system would itself result in VOC emissions and other products of combustion, it is presumed that thermal oxidation would result in minimal overall VOC emission reductions. Furthermore, no applications of thermal oxidation were demonstrated for a natural gas-fired auxiliary boiler in a review of the RBLC database. Therefore, while thermal oxidation as a VOC control technology may be considered technically feasible, it is not an "available" VOC control option for the proposed auxiliary boiler.

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[47] Rusu, Alice Oana and Dumitriu, Emil. 2003. "Destruction of Volatile Organic Compounds By Catalytic Oxidation." *Environmental Engineering and Management Journal*, 2(4):273-302.

5.4.3.3 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices are essential for the operation and life-span of the proposed auxiliary boiler and will be used with this auxiliary boiler. Therefore, good combustion practices are technically feasible.

Oxidation Catalyst

While an oxidation catalyst used to control CO emissions from a boiler may also reduce some VOC emissions, it is not considered technically feasible to use it with the auxiliary boiler because the auxiliary boiler is required to supply steam quickly to the combined cycle units during the startup procedure and the oxidation catalyst requires a high flue gas temperature to achieve effective control, which is not always achieved during the quick steam supply scenario. A more effective method of reducing emissions, including CO and VOC, is by good combustion controls and restricting operation on an annual basis.

Flue Gas Recirculation

FGR has been found to be technically feasible for use in auxiliary boilers, and therefore is considered further in the evaluation.

5.4.3.4 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

FGR and good combustion practices are technically feasible and compatible technologies used for the control of VOC and, therefore, a ranking has not been considered to establish a top technology.

5.4.3.5 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

AEC proposes to use good combustion practices and FGR as VOC LAER. Therefore, economic, environmental, and/or energy impacts were not assessed in this LAER analysis.

5.4.3.6 Step 5 – Proposed LAER

AEC proposes to use good combustion practices and FGR to control VOC emissions from the auxiliary boiler. A review was conducted of VOC LAER determinations for auxiliary boilers, including a search of the RBLC database and a review of information concerning recently permitted facilities with auxiliary boilers. Several facilities which have lower auxiliary boiler VOC emissions limits were identified.

Some facilities (Nucor Steel – Arkansas, Dart Container Corporation LLC, Nellis Air Force Base, Harrah's Operating Company, Inc., MGM Mirage, Toledo Supplier Park Paint Shop, Titan Tire Corporation Of Bryan, Oregon Clean Energy Center, US8 Facility, and Texstar Gas Process Facility) have a lower lb/hr or tpy emissions limit, but also have a higher lb/MMBtu emissions limit than what is proposed by AEC. Since the resulting VOC mass emissions rates from an auxiliary boiler are based on applying a LAER performance based lb/MMBtu emissions limit, the VOC mass limits for those facilities do not reflect a better control technology efficiency than proposed for the auxiliary boiler.

Several facilities (Nucor Decatur, LLC, Suwannee Mill, CPV St. Charles, Wildcat Point Generation Facility, Woodbridge Energy Center, MGM Mirage, Berks Hollow Energy Associates, Nucor Steel – Berkley, Klausner Holding USA, Inc., Port of Beaumont Petroleum Transload Terminal, CPV Valley Energy Center, York Energy Center Block 2, and Astoria Energy) have a more stringent VOC emissions limit when compared to the 0.004 lb/MMBtu emissions limit proposed by AEC. However, each facility is using the same add-on control technologies (good combustion practices and FGR) or fewer add-on control technologies as those proposed by AEC, and therefore the difference in emissions limits can be attributed to manufacturer differences resulting in differing emissions profiles.

Several facilities (Flopam Inc., Ray Compressor Station, Port of Beaumont Petroleum Transload Terminal, Cheyenne Prairie Generating Station, and Sunbury Generation LP) have a lower VOC emissions limit which is more stringent when comparted to the 0.004 lb/MMBtu emissions limit proposed by AEC. However, these facilities have boilers either much larger in size or much smaller in size. Since combustion efficiency is related to the three "T's" of combustion -- time, temperature, and turbulence -- boilers of different sizes, makes, and manufacturer's technology may allow for different combustion profiles.

In addition, AEC understands that several facilities (Magnolia LNG Facility, Indeck Niles, LLC, MEC North, LLC, MEC South, LLC, Hickory Run Energy Station, Eagle Mountain Steam Electric Station, Cricket Valley Energy Center, and Moundsville Combined Cycle Power Plant) have lower proposed emissions limits; however, they have yet to be built or have initial testing done, and therefore have not demonstrated their emissions limit in practice.

A complete list of facilities with natural gas-fired auxiliary boilers from the RBLC is included in Table D-B-3.

AEC proposes to use good combustion practices and FGR to control VOC emissions from the auxiliary boiler in order to achieve a VOC LAER emissions limit of 0.004 lb/MMBtu.

5.4.4 BACT for PM, PM_{10}, and $PM_{2.5}$

Emissions of PM, PM_{10}, and $PM_{2.5}$ are the result of inert solids contained in the fuel and combustion air. Unburned hydrocarbons in fuel may also form particles when not fully combusted. Emissions of PM were assumed to be different than emissions of PM_{10} and $PM_{2.5}$ in that PM_{10} and $PM_{2.5}$ emissions include both the filterable and condensable portions of particulate while emissions of PM include only the filterable portion of particulate. This section presents the PM, PM_{10}, and $PM_{2.5}$ BACT discussion for the auxiliary boiler.

5.4.4.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a control technology for reducing PM, PM_{10}, and $PM_{2.5}$ emissions from auxiliary boilers. The auxiliary boiler is designed for high combustion efficiency and the use of pipeline quality natural gas thereby making the particulate emissions inherently low. Limiting the amount of sulfur in the fuel is a common practice for natural gas-fired combustion equipment. The practical limitation is considered region-specific, depending on the source/specifications of the natural gas in the pipeline supplying plant. In addition, maintaining high combustion temperatures minimizes PM, PM_{10}, and $PM_{2.5}$ emissions that occur from incomplete combustion.

Fabric Filter Baghouses, ESPs, WESPs and Scrubbers

A fabric filter baghouse is a control technology used for reducing filterable PM, PM_{10}, and $PM_{2.5}$ from flue gas streams. Flue gas containing dust and condensables pass through filter tubes suspended in a housing unit. The particulate matter is collected by, and builds up on, the filter causing a filter cake to form, which is then removed periodically.

An ESP is also a control technology used for reducing filterable PM, PM_{10}, and $PM_{2.5}$ emissions. Particles within a flue gas stream are charged with an electric field and are attracted to oppositely charged collector plates. The particles are then removed from the collection plates by mechanical rapping which causes the buildup to fall into hoppers.

A WESP is a PM, PM_{10}, and $PM_{2.5}$ control technology that operates by essentially the same process as an ESP. The difference between the technologies is that a WESP removes the particles from the collection plates by means of liquid washing rather than mechanical rapping.

In addition, a scrubber is a control technology used to reduce PM, PM_{10}, and $PM_{2.5}$ emissions through the impaction, diffusion interception and/or absorption of particulate onto droplets of liquid.[48] Water or another liquid is sprayed into the exhaust airstream so that it comes into contact with suspended particulate. Collection efficiency depends greatly on particle size, with decreasing particle size leading to decreased efficiency.

5.4.4.2 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices, including the use of low sulfur fuels, are essential for the operation and life-span of the proposed auxiliary boiler, and will be used with this auxiliary boiler. Therefore, good combustion practices are technically feasible.

Fabric Filter Baghouses, ESPs, WESPs and Scrubbers

Fabric filter baghouses, ESPs, WESPs, and scrubbers are post combustion technologies for reducing PM, PM_{10}, and $PM_{2.5}$ emissions. A review of recently permitted facilities and a search of the RBLC database found that fabric filter baghouses, ESPs, WESPs, and/or scrubbers were not identified as control technologies that have been applied on natural gas-fired auxiliary boilers similar to the proposed auxiliary boiler. Therefore, while fabric filter baghouses, ESPs, WESPs, and/or scrubbers may be considered technically feasible as control technologies for PM, PM_{10}, and $PM_{2.5}$, they are not "available" for the proposed auxiliary boiler and are not considered further.

5.4.4.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices are a technically feasible control technology used for the control of PM, PM_{10}, and $PM_{2.5}$ emissions. Therefore, a ranking is not necessary to establish the top technology.

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[48] U.S. EPA Control Cost Manual, Section 6, Chapter 2 – Wet Scrubbers for Particulate Matter

5.4.4.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices will be implemented as part of the design and operation of the auxiliary boiler. While fabric filter baghouses, ESPs, and scrubbers may be technically feasible, they are not considered "available" for the proposed auxiliary boiler. Because PM, PM_{10}, and $PM_{2.5}$ emissions from the auxiliary boiler are all less than 1.61 tpy combined, even if a baghouse provided 99% control, the capital and operating costs associated with an add-on particulate matter control device (e.g., baghouse, ESP, WESP, etc.) would result in excessive cost effectiveness values.

5.4.4.5 Step 5 – Proposed BACT

AEC proposes good combustion practices as BACT for the auxiliary boiler to minimize emissions of PM, PM_{10}, and $PM_{2.5}$. The same control technologies are applied for each pollutant; however, AEC has determined separate limits for each PM, PM_{10}, and $PM_{2.5}$.

Particulate Matter

AEC conducted a review of the RBLC database and recently permitted facilities to identify auxiliary boilers with lower PM emissions limits (Mockingbird Hill Compressor Station, Woodbridge Energy Center, and Toledo Supplier Park – Paint Shop). Woodbridge Energy Center and Toledo Supplier Park – Paint Shop have a lower lb/hr emissions limit, but also have a higher lb/MMBtu emissions limit than what is proposed by AEC. Since the resulting PM mass emissions rate from an auxiliary boiler are based on applying a BACT performance based lb/MMBtu emissions limit, the PM limit for those facilities does not reflect a better control technology efficiency than what is proposed for the auxiliary boiler. In addition, Mockingbird Hill Compressor Station and Toledo Supplier Park – Paint Shop both have boilers much smaller than the proposed unit with different emissions profiles, therefore their limits cannot be compared.

A complete list of facilities with natural gas-fired auxiliary boilers from the RBLC is included in Table D-B-4.

AEC proposes good combustion practices and the exclusive use of natural gas as BACT for PM for the auxiliary boiler to achieve an emissions limit of 0.00181 lb/MMBtu.

PM_{10}/$PM_{2.5}$

A review of the RBLC database and recently permitted facilities for auxiliary boilers firing natural gas was conducted. The search returned no results of facilities with lower PM_{10}/$PM_{2.5}$ emissions limits. A complete list of facilities with natural gas-fired dew point heaters from the RBLC is included in Table D-B-5 and Table D-B-6.

Therefore, AEC proposes good combustion practices, including the use of low sulfur fuel, as BACT for PM_{10}/$PM_{2.5}$ for the auxiliary boiler to achieve an emissions limit of 0.00149 lb/MMBtu.

5.4.5 BACT for SO_2

This section presents the SO_2 BACT discussion for the auxiliary boiler. SO_2 results from the oxidation of fuel sulfur. SO_2 is formed when sulfur contained in the fuel is burned, combining with O_2 in the combustion air to create SO_2.

5.4.5.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are an available control technology for SO_2 emissions from small natural gas-fired auxiliary boilers (i.e., less than 100 MMBtu/hr). Good combustion practices include the use of low sulfur fuels (i.e., natural gas), as well as maintaining optimum combustion efficiency and implementing appropriate maintenance procedures.

Scrubber/Flue Gas Desulfurization

A scrubber (or desulfurization unit) is a control technology used to control SO_2 emissions. Scrubbers use chemical and mechanical processes to remove SO_2 from the exhaust gas. According to a search of recently permitted facilities and the RBLC database, there are currently no natural gas-fired auxiliary boilers that employ this technology. Therefore, scrubbers are not considered "available" for the auxiliary boiler and are not considered in this BACT analysis further.

5.4.5.2 Step 2 – Eliminate Technically Infeasible Options

Good combustion practices, including the use of low sulfur fuels, are essential for the operation and life-span of the auxiliary boiler. Therefore, good combustion practices are technically feasible for the proposed auxiliary boiler.

5.4.5.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices and low sulfur fuels are the only remaining technically feasible technologies for controlling SO_2 emissions. Therefore, a ranking is not necessary to establish the top technology.

5.4.5.4 Step 4 – Evaluate Economic, Environmental and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices and low sulfur fuels will be implemented as part of the design and operation of the auxiliary boiler. Therefore, economic, environmental, and/or energy impacts were not assessed in this BACT analysis.

5.4.5.5 Step 5 – Proposed BACT

AEC proposes to use good combustion practices, including the use of low sulfur fuels, to control SO_2 emissions from the auxiliary boiler. A review was conducted of SO_2 BACT determinations for auxiliary boilers, including a search of the RBLC database and a review of information concerning recently permitted facilities with auxiliary boilers. Several facilities which have lower auxiliary boiler SO_2 emissions limits were identified.

Several facilities identified as having lower limits (Dania Beach Energy Center, Lake Charles Methanol Facility, Indeck Niles, LLC, and Moundsville Combined Cycle Power Plant) have not been built yet and, therefore, the limits have not been demonstrated in practice.

Several facilities (Thyssenkrupp Steel and Stainless Steel USA, LLC, Nucor Decatur LLC, Wildcat Point Generation Facility, Hess Newark Energy Center, MGM Mirage, Republic Steel, Berks Hollow Energy Association LLC, and Nucor Steel - Berkeley) have a more stringent SO_2 emissions limit when compared to the 0.0011 lb/MMBtu emissions limit proposed by AEC. However, each facility is using the same control technologies (good combustion practices) or fewer add-on control technologies as those proposed by AEC, and therefore the difference in emissions limits can be attributed to manufacturer differences.

Several facilities (Nucor Steel – Arkansas, Harrah's Operating Company, Inc., Nellis Air Force Base, Caithnes Bellport Energy Center, Toledo Supplier Park – Paint Shop, Chouteau Power Plant, and Sunbury Generation LP) have a lower SO_2 emissions limit which is more stringent when comparted to the 0.0011 lb/MMBtu emissions limit proposed by AEC. However, these facilities have boilers either much larger in size or much smaller in size, therefore their emissions limits cannot be compared due to differences in emissions profiles.

A complete list of facilities with natural gas-fired auxiliary boilers from the RBLC is included in Table D-B-7.

Thus, AEC proposes exclusive use of natural gas with a sulfur content of 0.4 gr S/100 SCF and the use of good combustion practices, as BACT to minimize emissions of SO_2 from the auxiliary boiler. These technologies represent the most stringent controls available for the auxiliary boiler and will be used to achieve a SO_2 emissions limit of 0.0011 lb/MMBtu.

5.4.6 **BACT for H_2SO_4**

This section presents the H_2SO_4 BACT discussion for the auxiliary boiler. Emissions of H_2SO_4 from the natural gas-fired auxiliary boiler result from oxidation of sulfur contained within the fuel.

While there are no post-combustion control technologies available for H_2SO_4, for completeness purposes, a top-down BACT analysis for H_2SO_4 was performed.

5.4.6.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling H_2SO_4 emissions from small natural gas-fired boilers (i.e., less than 100 MMBtu/hr). Good combustion practices include the use of low sulfur fuels (e.g., natural gas), as well as maintaining optimum combustion efficiency and implementing appropriate maintenance procedures. A review of the RBLC database and other recently permitted facilities indicates no other available H_2SO_4 control technologies.

5.4.6.2 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices, including the use of low sulfur fuels, are essential for the operation and life-span of the proposed auxiliary boiler, and will be used with this auxiliary boiler. Therefore, good combustion practices are technically feasible.

5.4.6.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices are the only technically feasible control technology for H_2SO_4; therefore, a ranking has not been considered to establish a top technology.

5.4.6.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices will be implemented as part of the design and operation of the natural gas-fired auxiliary boiler. Therefore, economic, environmental, and/or energy impacts were not assessed in this BACT analysis.

5.4.6.5 Step 5 – Proposed BACT

AEC proposes to use good combustion practices as H_2SO_4 BACT for the auxiliary boiler. To determine the appropriate proposed BACT limits, a search of the RBLC database and other recently permitted facilities was conducted for similar auxiliary boilers. The search identified auxiliary boilers with lower emissions limits (Belle River Combined cycle power plant, Middlesex Energy Center, and Moundsville Combined Cycle Power Plant). However, these facilities have not been built yet and therefore the limits have not been demonstrated in practice. Additionally, some facilities with lower limits were identified (Marshalltown Generating Station, CPV St. Charles, Oregon Clean Energy Center, Woodbridge Energy Center, and York Energy Center Block 2) that have a H_2SO_4 emissions limit which are more stringent when compared to the 0.000135 lb/MMBtu emissions limit proposed by AEC. However, these facilities are using the same control technologies as those proposed by AEC, and therefore the difference in emissions limits can be attributed to manufacturer differences that result in differing emissions profiles. More importantly, as H_2SO_4 is a function of the sulfur content in the fuel, the assumption is that 100% of the sulfur in the fuel is converted to SO_2, 10% of the SO_2 is converted to SO_3, and 100% of the SO_3 is converted to H_2SO_4. One facility (Hess Newark Energy Center) uses a 5% conversion rate of SO_2 to SO_3, and thus may not be compared to the emissions limit proposed by AEC. Therefore, AEC proposes the use of good combustion practices as BACT to minimize emissions of H_2SO_4 from the auxiliary boiler. This represents the most stringent controls available for the auxiliary boiler and will be utilized to achieve a H_2SO_4 emissions limit of 0.000135 lb/MMBtu. A complete list of facilities with natural gas-fired auxiliary boilers from the RBLC is included in Table D-B-8.

5.4.7 **BACT for GHG**

GHG emissions from the auxiliary boiler result from oxidation of fuel carbon. This evaluation does not identify and discuss each of the five individual steps of the top-down BACT process, as CCS was determined not to be cost effective for the Facility-wide GHG emissions (see Section 5.3.7).

A review was conducted of GHG BACT determinations for auxiliary boilers, including a search of the RBLC database and a review of information concerning recently permitted facilities with auxiliary boilers. The results of the search, which can be found in Appendix D Table D-B-9, confirmed that the proposed GHG emissions limits for the auxiliary boiler are consistent with auxiliary boilers at recently permitted facilities and entries in the RBLC.

The use of energy efficient design and work practices will be used to minimize GHG emissions. Emissions from the auxiliary boiler will be included in an annual Facility-wide GHG limit calculated on a 12-month rolling average which can be found in Table 5-17.

5.5 CONTROL TECHNOLOGY ANALYSIS FOR THE DEW POINT HEATER

This section presents the BACT and LAER determination process for the dew point heater for H_2SO_4, CO, PM, PM_{10}, $PM_{2.5}$, SO_2 and GHG and NO_X and VOC, respectively. The processes by which pollutants are formed in a dew point heater mirror those occurring in an auxiliary boiler. As such, similar available control technologies associated with the auxiliary boiler also apply to a dew point heater. Table 5-21 presents a summary of the proposed BACT and LAER limits for the dew point heater.

Table 5-21
Proposed BACT/LAER for the Dew Point Heater
Invenergy LLC – Allegheny Energy Center

Pollutant[(a)]	BACT	Fuel	Proposed Emissions Limit	Emissions Limit Units	Averaging Period
NO_X	Good combustion practices	Natural Gas	0.011	lb/MMBtu	Average of three test runs
			0.03	lb/hr	
CO	Good combustion practices	Natural Gas	0.037	lb/MMBtu	Average of three test runs
			0.11	lb/hr	
VOC	Good combustion practices	Natural Gas	0.005	lb/MMBtu	Average of three test runs
			0.02	lb/hr	
PM	Good combustion practices and low sulfur fuels	Natural Gas	0.0048	lb/MMBtu	Average of three test runs
			0.01	lb/hr	
$PM_{2.5}$/ PM_{10}	Good combustion practices and low sulfur fuels	Natural Gas	0.0015	lb/MMBtu	Average of three test runs
			0.0045	lb/hr	
SO_2	Good combustion practices and low sulfur fuels	Natural Gas	0.0011	lb/MMBtu	Average of three test runs
			0.0033	lb/hr	
H_2SO_4	Good combustion practices and low sulfur fuels	Natural Gas	0.000135	lb/MMBtu	Average of three test runs
			0.0004	lb/hr	
GHG	Energy efficient design and work practices	Natural Gas	Will comply with Facility-wide GHG emissions limit.		

(a) Emissions limit of $PM_{2.5}$/PM_{10} are inclusive of the condensable portion and filterable portion of particulate, while the emissions limit of PM represents the filterable portion only.

5.5.1 LAER for NO_X

The Project will be subject to LAER for NO_X, because estimated potential emissions of NOx will be greater than the 100 tpy Major Stationary Source threshold applicable to an O_3 precursor in the Northeast Ozone Transport Region. NO_X emissions from the Project are also subject to PSD review, including BACT requirements. This section demonstrates that the proposed NO_X emissions and controls meet the requirements of LAER. Because LAER requirements are at least as stringent as BACT, the LAER analysis also satisfies the BACT demonstration for NOx.

NO_X is primarily formed by two mechanisms: the combination of elemental N_2 and O_2 in the combustion air within the high temperature environment of the combustor (thermal NO_X); and the oxidation of N_2 contained in the fuel (fuel NO_X). When firing natural gas, NO_X emissions from the dew point heater originate primarily as thermal NO_X. The rate of formation of thermal NO_X is a function of residence time and free O_2 and is exponential with peak flame temperature.

5.5.1.1 Identification of Most Stringent State Implementation Plan Limitation in Any State

As part of a LAER analysis the most stringent emissions limitations that are contained in the SIP of any State for such class or category of stationary sources were identified. States that contain the most severe ozone nonattainment areas typically contain the most stringent NO_X limits in their SIPs. Therefore, the NO_X control rules potentially applicable to dew point heaters fired with natural gas were reviewed and summarized for the following states and/or AQMD in Table 5-19.

Table 5-22
NO_X Dew Point Heater SIP Limitations in Other Nonattainment States
Invenergy LLC – Allegheny Energy Center

State/AQMD	Regulatory Limit	Citation
Bay Area AQMD, CA	30 ppmvd @ 3 % O_2 (0.04 lb/MMBtu) for natural gas-fired boiler, steam generator or process heaters >2 to 5 MMBtu/hr;	BAAQMD Regulation 9, Rule 9, 9-7-307.1
San Joaquin Valley Unified (SJVU) AQMD	15 ppmvd @ 3 percent O_2 (0.018 lb/MMBtu) for natural gas-fired boiler, steam generator or process heater <20 MMBtu/hr	SJVUAQMD Rule 4306, Boilers, steam generators and process heaters – phase 2
Texas Commission on Environmental Quality (TCEQ)	No Applicable NO_X Limit	

Table 5-22
NO_X Dew Point Heater SIP Limitations in Other Nonattainment States
Invenergy LLC – Allegheny Energy Center

State/AQMD	Regulatory Limit	Citation
New Jersey Department of Environmental Protection	No Applicable NO_X Limit	
Massachusetts Department of Environmental Protection	0.2 lb/MMBtu for boilers burning only gas	310 CMR 7.19 – Reasonably Available Control Technology for Sources of Nitrogen Oxides
New York State Department of Environmental Conservation	No Applicable NO_X Limit	
Connecticut Department of Environmental Protection	0.20 lb/MMBtu for natural gas-fired boiler	RCSA 22a-174-22 Control of Nitrogen Oxides Emissions

The most stringent applicable NO_X emissions limitation identified from this review of SIPs comprising the most severe ozone nonattainment areas is 15 ppmvd NO_X @ 3 percent O_2. The proposed dew point heater, which will have a maximum design heat input of 3.0 MMBtu/hr is not subject to NSPS Subpart Dc per 40 CFR §60.40c(e). As discussed in this section, SCR is not feasible for control of the dew point heater, thus the proposed NO_X emissions limit for the dew point heater is 0.011 lb/MMBtu for LAER/BACT.

5.5.1.2 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling NO_X emissions from a dew point heater.

Maintaining optimum combustion efficiency or implementing appropriate maintenance procedures are examples of good combustion practices.

Selective Catalytic Reduction

SCR is a control technology used to convert NO_X into diatomic N_2 and H_2O using a catalyst. The reduction reactions used by SCR require O_2, so it is most effective at O_2 levels above 2-3%. SCR can achieve a NO_X reduction rate in the range of 70 - 90%.[49] Base metals, such as vanadium or titanium, are often used for the catalyst due to their effectiveness as a control technology for NO_X and cost-effectiveness for use with natural gas combustion. In addition, a gaseous reductant such as $NH_{3(aq)}$ is added to the flue gas and absorbed onto the catalyst.[50] The problems associated with the catalysts used for SCR are the lack of high thermal durability of the base metals and their potential to oxidize SO_2 into SO_3.

Low-NO_X Burners

LNB is an example of a front-end control technology for limiting NO_X emissions from a dew point heater. LNB limit peak flame temperature by separating combustion into multiple stages, which results in uniform temperatures below the peak NO_X formation temperature range and thereby lowering NO_X emissions.

Ultra-Low-NO_X Burners

Similar to LNB, ULNB is another example of a front-end control technology for limiting NO_X emissions from a dew point heater. While ULNB limit peak flame temperature by separating

[49] EPA (U.S. Environmental Protection Agency). 2003. "Selective Catalytic Reduction Air Pollution Control Technology Fact Sheet." *EPA-452/F-03-032*

[50] The U.S. Department of Energy and Southern Company Services, Inc., "Control of Nitrogen Oxide Emissions: Selective Catalytic Reduction (SCR)"

combustion into multiple stages, ULNB use more advanced techniques, such as internal FGR and lean premixing of the air and fuel, to reduce NO_X emissions to negligible levels.

Flue Gas Recirculation

FGR is a control technology used for limiting emissions of NO_X from a dew point heater. The technology works by returning up to 25% of the flue gas from a burner back to the combustion chamber. This can be done with hot gas fans and combustion air duct mixing devices (known as forced FGR) or via induced FGR, which routes flue gas through ducts directly into the existing forced draft fan inlet. The flue gas absorbs heat from the flame, lowering the peak flame temperature and reducing NO_X formation. The flue gas also mixes with the combustion air and lowers the oxygen content of the air, thereby limiting the NO_X-forming reaction. This simple and effective control technology is part of the heating process design.

5.5.1.3 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices, including the use of low sulfur fuels, are essential for the operation and life-span of the proposed dew point heater, and will be used with this dew point heater. Therefore, good combustion practices are technically feasible.

Selective Catalytic Reduction

While an SCR may be considered a technically feasible control technology, which can be used as supplemental control with LNB or ULNB, it has not been applied on gas-fired heaters of similar size as the proposed unit. Therefore, it is not considered a technically "available" control option for this analysis and is not considered further.

Low-NO_X Burners

While the use of LNB may be considered a technically feasible control technology, it has not been demonstrated in practice on small gas-fired heaters such as the proposed unit. Therefore, it is not considered a technically available control option for this analysis and therefore is not considered further.

Ultra-Low-NO_X Burners

While the use of ULNB may be considered a technically feasible control technology, it has not been applied on small gas-fired heaters as small as the proposed unit. Therefore, it is not considered a technically available control option for this analysis and therefore is not considered further.

Flue Gas Recirculation

While the use of FGR may be considered a technically feasible control technology, it has not been applied on small gas-fired heaters as small as the proposed unit. Therefore, it is not considered a technically available control option for this analysis and therefore is not considered further.

5.5.1.4 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices are technically feasible control technologies for NO_X; therefore, a ranking has not been considered to establish a top technology.

5.5.1.5 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices will be implemented as part of the design and operation of the dew point heater. Therefore, economic, environmental, and/or energy impacts were not assessed in this LAER analysis.

5.5.1.6 Step 5 – Proposed LAER/BACT

AEC proposes to use good combustion practices as NO_X LAER/BACT for the dew point heater to achieve the emissions limit presented in Table 5-23.

Table 5-23
Proposed NO_X LAER for the Dew Point Heater
Invenergy LLC – Allegheny Energy Center

Emissions Unit	Fuel	LAER	Proposed Emissions Limit	Emissions Limit Units	Averaging Period
Dew Point Heater	Natural Gas	good combustion practices	0.011	lb/MMBtu	Three (3) hour block

A review of the RBLC database and recently permitted facilities for dew point heaters firing natural gas was conducted. The search returned no results of facilities with lower NO_X limits. A complete list of facilities with natural gas-fired dew point heaters from the RBLC is included in Table D-C-1.

Therefore, AEC proposes good combustion practices as NO_X BACT for the proposed dew point heater to achieve an emissions limit of 0.011 lb/MMBtu.

5.5.2 **BACT for CO**

This section presents the CO BACT discussion for the dew point heater. The rate of CO emissions from dew point heaters depends on the efficiency of natural gas combustion. Improperly tuned dew point heaters and dew point heaters operating at off-design levels decrease combustion efficiency, which results in increased CO emissions.

5.5.2.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling CO emissions from the dew point heater. Maintaining optimum combustion efficiency and/or implementing appropriate maintenance procedures are examples of good combustion practices.

Oxidation Catalyst

Catalytic oxidation is an add-on control technology designed to reduce CO emissions. The catalysts are typically made of a precious metal and operate at temperatures in the range of 205 to 260°F.[51] The catalysts cause excess O_2 to react with CO to form CO_2.

Thermal Oxidation

Thermal oxidation is also an add-on control technology designed to reduce CO emissions. Thermal oxidation reduces CO emissions by supplying sufficient O_2 at temperatures of at least 1,400°F,[52] thus combusting CO into CO_2 and water.

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[51] Rusu, Alice Oana and Dumitriu, Emil. 2003. "Destruction of Volatile Organic Compounds By Catalytic Oxidation." *Environmental Engineering and Management Journal*, 2(4):273-302.

[52] EPA (U.S. Environmental Protection Agency). 2003. “Regenerative Incinerator Air Pollution Control Technology Fact Sheet.” *EPA-452/F-03-021*

5.5.2.2 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices, including the use of low sulfur fuels, are essential for the operation and life-span of the proposed dew point heater. Therefore, good combustion practices are technically feasible, and will be used with this dew point heater.

Oxidation Catalyst

Catalytic oxidation is a proven post-combustion control technology that uses a catalyst matrix to oxidize CO, VOC, and other pollutants. In order for the dew point heater to meet the minimum temperature requirement for catalytic oxidation to be effective, the system would need to be equipped with a supplementary pre-heater to raise the exhaust gas temperature. This add-on control option adds to the complexity, costs, and emissions associated with the overall system. In addition, PM and moisture in the exhaust stream can cause fouling and deactivation of the catalyst. Because of the dew point heater's small size, and the lack of catalytic oxidation add-on technology identified for similar sized dew point heaters in the RBLC database or in the review of recently permitted facilities, AEC has considered this technology to not be an "available" control technology for the dew point heater.

Thermal Oxidation

Thermal oxidation reduces CO emissions by supplying sufficient oxygen at temperatures of at least 1,400°F.[53] Because the exhaust gas temperature is significantly lower than the temperature that is required, a supplementary-fired burner would be needed to achieve the operating temperature of a thermal oxidation system. Since the combustion of the fuel for an oxidation system would itself result in CO emissions, it is presumed that thermal oxidation would result in

[53] EPA (U.S. Environmental Protection Agency). 2003. "Regenerative Incinerator Air Pollution Control Technology Fact Sheet." *EPA-452/F-03-021*

minimal overall CO emission reductions. Furthermore, no applications of thermal oxidation were identified for dew point heaters in a review of the RBLC database. Therefore, while thermal oxidation as a CO control technology may be considered technically feasible, it is not an “available” CO control option for the dew point heater.

5.5.2.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices are technically feasible control technologies for CO. Therefore, a ranking has not been considered to establish a top technology.

5.5.2.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

While an oxidation catalyst and thermal oxidation may, in theory, be considered technically feasible, because the additional fuel required to raise the temperature of the gas stream would ultimately increase the emissions from the dew point heater, these add-on control technologies were not considered “available” for use on the dew point heater. Therefore, AEC is proposing the use of good combustion practices to achieve the most stringent CO emissions limit for the proposed dew point heater.

5.5.2.5 Step 5 – Proposed BACT

AEC proposes good combustion practices for the dew point heater as BACT in order to minimize emissions of CO. A search of the RBLC database and recently permitted facilities was conducted to identify dew point heaters with lower CO emissions limits. The results of this search are summarized in Appendix D. Greensville Power Station has a lower CO emissions limit of 0.035 lb/MMBtu achieved through clean fuels and good combustion practices. The emissions limit from Greensville Power Station is essentially equivalent to the proposed limit by AEC and uses the same control methods. Therefore, AEC proposes good combustion practices as BACT to control CO emissions from the dew point heater to achieve an emissions limit of 0.037 lb/MMBtu.

A complete list of facilities with natural gas-fired dew point heaters from the RBLC is included in Table D-C-2.

5.5.3 LAER for VOC

The Project will be subject to LAER for VOC, because estimated potential emissions of VOC from the Project will be greater than the 50 tpy Major Stationary Source threshold applicable to O_3 precursor VOC emissions in the Northeast Ozone Transport Region. VOC emissions from the Project are also subject to PSD review, including BACT requirements. This section demonstrates that the proposed VOC emissions and controls meet the requirements of LAER. Because LAER requirements are at least as stringent as BACT, the LAER analysis also satisfies the BACT demonstration for VOC.

VOC emissions occur as a result of incomplete combustion of hydrocarbons in fuel. As such, similar available control technologies associated with the auxiliary boiler also apply to a dew point heater. AEC has evaluated the control of VOC emissions from the proposed dew point heater in order to determine LAER.

5.5.3.1 Identify the Most Stringent State Implementation Plan Limitation in Any State

The VOC control rules potentially applicable to natural gas-fired process heaters were reviewed and summarized for the following states and/or AQMD in Table 5-20.

Table 5-24
VOC Dew Point Heater SIP Limitations in Other Nonattainment States
Invenergy LLC – Allegheny Energy Center

State/AQMD	Regulatory Limit	Citation
Bay Area AQMD, CA	No applicable VOC limit.	BAAQMD Regulation 9
San Joaquin Valley Unified (SJVU) AQMD	No applicable VOC limit.	SJVUAQMD Rule 4307, BOILERS, STEAM GENERATORS, AND PROCESS HEATERS – 2.0 MMBtu/hr to 5.0 MMBtu/hr
Texas Commission on Environmental Quality	No applicable VOC limit.	Chapter 115 – Control of Air Pollution from Volatile Organic Compound Sources
New Jersey Department of Environmental Protection	No applicable VOC limit.	New Jersey Administrative Code, Title 7:27-16.8 – Boilers
Massachusetts Department of Environmental Protection	No applicable VOC limit.	310 CMR 7.00
New York State Department of Environmental Conservation	No applicable VOC limit.	6NYCRR, Chapter III
Connecticut Department of Environmental Protection	No applicable VOC limit.	RCSA 22a-174
Pennsylvania Department of Environmental Protection	No applicable VOC limit.	Title 25 of the Pa. Code, Subpart C, Article III Air Resources
Florida Department of Environmental Protection	No applicable VOC limit.	Chapter 62-296.570, F.A.C., Stationary Sources – Emission Standards
Georgia Department of Natural Resources, Environmental Protection Division	No applicable VOC limit.	Chapter 391-3-1, Rule: .02 Provisions.
Illinois Environmental Protection Agency	No applicable VOC limit.	Title 35, Illinois Administrative Code

No VOC emissions limitations applicable to the dew point heater were identified from this review of SIPs comprising the most severe ozone nonattainment areas. There are no NSPS that specify VOC limits for the dew point heater, therefore AEC proposes an VOC emissions limit of 0.005 lb/MMBtu.

5.5.3.2 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling VOC emissions from a dew point heater. Maintaining optimum combustion efficiency or implementing appropriate maintenance procedures are examples of good combustion practices.

Oxidation Catalyst

Catalytic oxidation is an add-on control technology designed to reduce VOC emissions. The catalysts are usually made of a precious metal and they operate at temperatures in the range of 205 to 260°F.[54] The catalyst cause excess O_2 to react with VOCs to form H_2O and CO_2. However, an issue with catalytic oxidation is the catalyst's susceptibility to poisoning by fine particles in the exhaust gas, which reduces the catalyst's effectiveness.

Flue Gas Recirculation

FGR has been used to control both NO_X and VOC emissions. This technology allows the combustion process to occur with less excess air and without increasing the combustion chamber temperature, which results in minimizing VOC emissions.

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[54] Rusu, Alice Oana and Dumitriu, Emil. 2003. "Destruction of Volatile Organic Compounds By Catalytic Oxidation." *Environmental Engineering and Management Journal*, 2(4):273-302.

5.5.3.3 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices, including the use of low sulfur fuels, are essential for the operation and life-span of the proposed dew point heater. Therefore, good combustion practices are technically feasible, and will be used with this dew point heater.

Oxidation Catalyst

While the use of an oxidation catalyst may be considered a technically feasible control technology, it has been not been used historically on dew point heaters small in size, such as the proposed unit. Therefore, it is not considered a technically available control option for this analysis.

Flue Gas Recirculation

While the use of FGR may be considered a technically feasible control technology, it has been not been used historically on dew point heaters small in size, such as the proposed unit. Therefore, it is not considered a technically available control option for this analysis.

5.5.3.4 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only feasible control technology for the dew point heater is good combustion practices. Therefore, a ranking has not been considered to establish a top technology.

5.5.3.5 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

The only feasible control technology for the dew point heater is good combustion practices. Therefore, the economic, environmental, and/or energy impacts have not been evaluated.

5.5.3.6 Step 5 – Proposed LAER

AEC proposes the limits presented in Table 5-25 as VOC LAER for the dew point heater to be achieved through the use good combustion practices.

Table 5-25
Summary of LAER for the Dew Point Heater
Invenergy LLC – Allegheny Energy Center

Emission Unit	Pollutant	Fuel	Proposed Emission Limit	Emission Limit Units	Control Method
Dew Point Heater	VOC	Natural Gas	0.005	lb/MMBtu	Good combustion practices

Review of the RBLC indicates that there are no facilities with a lower limit than the 0.005 lb/MMBtu of VOC proposed by AEC as LAER.

A complete list of facilities with natural gas-fired dew point heaters from the RBLC is included in Table D-C-3.

Therefore, AEC proposes to use good combustion practices to control VOC emissions from the dew point heater to achieve a VOC BACT emissions limit of 0.005 lb/MMBtu.

5.5.4 **BACT for PM, PM_{10}, and $PM_{2.5}$**

Emissions of PM, PM_{10}, and $PM_{2.5}$ are the result of inert solids contained in the fuel and combustion air. Unburned hydrocarbons in fuel may also form particles when not fully combusted. Emissions of PM were assumed to be different than emissions of PM_{10} and $PM_{2.5}$ in that PM_{10} and $PM_{2.5}$ emissions include both the filterable and condensable portions of particulate while emissions of PM include only the filterable portion of particulate. This section presents the PM, PM_{10}, and $PM_{2.5}$ BACT discussion for the dew point heater.

5.5.4.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling PM, PM_{10}, and $PM_{2.5}$ emissions from a dew point heater. Maintaining optimum combustion efficiency or implementing appropriate maintenance procedures are examples of good combustion practices.

Fabric Filter Baghouses, ESPs, WESPs and Scrubbers

A fabric filter baghouse is a control technology used for reducing filterable PM, PM_{10}, and $PM_{2.5}$ from flue gas streams. Flue gas containing dust and condensables pass through filter tubes suspended in a housing unit. The particulate matter builds up on the filter causing a filter cake to form, which is then removed periodically.

An ESP is also a control technology used for reducing filterable PM, PM_{10}, and $PM_{2.5}$ emissions. Particles of a flue gas stream are charged with an electric field and are attracted to oppositely charged collector plates. The particles are then removed from the collection plates by means of mechanical rapping which causes the buildup to fall into the hoppers.

A WESP is a PM, PM_{10}, and $PM_{2.5}$ control technology that operates by essentially the same process as an ESP. The difference between the technologies is that a WESP removes the particles from the collection plates by means of liquid washing rather than mechanical rapping.

In addition, a scrubber is a control technology used to reduce PM, PM_{10}, and $PM_{2.5}$ emissions through the impaction, diffusion interception and/or absorption of particulate onto droplets of liquid.[55] Water or another liquid is sprayed into the exhaust airstream so that it comes into contact

[55] U.S. EPA Control Cost Manual, Section 6, Chapter 2 – Wet Scrubbers for Particulate Matter

with suspended particulate. Collection efficiency depends greatly on particle size, with decreasing particle size leading to decreased efficiency.

5.5.4.2 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices, including the use of low sulfur fuels, are essential for the operation and life-span of the proposed dew point heater, and will be used with this dew point heater. Therefore, good combustion practices are technically feasible.

Fabric Filter Baghouses, ESPs, WESPs and Scrubbers

Fabric filter baghouses, ESPs, WESPs, and scrubbers are add-on technologies for reducing PM, PM_{10}, and $PM_{2.5}$ emissions. A review of recently permitted facilities and a search of the RBLC database found that fabric filter baghouses, ESPs, WESPs, and/or scrubbers were not identified as control technologies that have been applied on dew point heaters similar to the proposed dew point heater. Therefore, while fabric filter baghouses, ESPs, WESPs, and/or scrubbers may be considered technically feasible as control technologies for PM, PM_{10}, and $PM_{2.5}$, they are not "available" for the proposed dew point heater and are not considered further.

5.5.4.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Based on a review of the RBLC database and other permit determinations, good combustion practices, including the use of low sulfur fuels, is a technically feasible control technology for PM, PM_{10}, and $PM_{2.5}$ from the proposed dew point heater. Therefore, a ranking is not necessary to establish the top technology.

5.5.4.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

While fabric filter baghouses, ESPs, and scrubbers may be technically feasible, they are not considered "available" for the proposed dew point heater. Because PM, PM_{10}, and $PM_{2.5}$ emissions from the dew point heater are each less than 0.4 tpy controlling PM, PM_{10}, and $PM_{2.5}$ emissions would not be cost effective. Therefore, fabric filter baghouses, ESPs and scrubbers are not economically feasible.

5.5.4.5 Step 5 – Proposed BACT

Good combustion practices, including the exclusive use of natural gas with a sulfur content of 0.4 gr S/100 SCF, will be implemented as part of the design and operation of the dew point heater and are considered BACT. The same control technologies are applied for each pollutant; however, AEC has determined separate limits for PM, PM_{10}, and $PM_{2.5}$.

Particulate Matter

A search was conducted of the RBLC database and recently permitted facilities. Two facilities (Indeck Niles, LLC, and Belle River Combined Cycle Power Plant) were identified as having lower PM limits. However, these facilities have not completed construction and thus have not demonstrated their limits in practice. Therefore, AEC proposes good combustion practices and the exclusive use of natural gas as BACT for PM for the dew point heater in order to achieve an emissions limit of 0.0048 lb/MMBtu.

A complete list of facilities with natural gas-fired dew point heaters from the RBLC is included in Table D-C-4.

PM_{10}/$PM_{2.5}$

A search was conducted of the RBLC database and recently permitted facilities. AEC has identified one facility, Grayling Particleboard, that has a dew point heater with lower PM_{10}/$PM_{2.5}$

limit of 0.0005 lb/MMBtu for PM_{10} and 0.004 lb/MMBtu for $PM_{2.5}$. However, this facility has not been built yet and the limits have not been demonstrated in practice.

A complete list of facilities with natural gas-fired dew point heaters from the RBLC is included in Table D-C-5 and Table D-C-6.

Therefore, AEC proposes good combustion practices and the exclusive use of natural gas as BACT for $PM_{10}/PM_{2.5}$ for the dew point heater in order to achieve an emissions limit of 0.007 lb/MMBtu.

5.5.5 **BACT for SO_2**

This section presents SO_2 BACT for the dew point heater. SO_2 results from the oxidation of fuel sulfur. SO_2 is formed when sulfur contained in the fuel is burned, combining with O_2 in the combustion air to create SO_2.

5.5.5.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are available control technologies for SO_2 emissions from dew point heaters. Good combustion practices include the use of low sulfur fuels (e.g., natural gas), as well as maintaining optimum combustion efficiency and implementing appropriate maintenance procedures.

Scrubber/Flue Gas Desulfurization

A scrubber (or desulfurization unit) is a control technology used to control SO_2 emissions. Scrubbers use chemical and mechanical processes to remove SO_2 from the exhaust gas. According to a search of recently permitted facilities and the RBLC database, there are currently no dew point heaters that employ this technology. Therefore, scrubbers are not considered available for the dew point heater and are not discussed in this BACT analysis further.

5.5.5.2 Step 2 – Eliminate Technically Infeasible Options

Good combustion practices, including the use of low sulfur fuels, are essential for the operation and life-span of the dew point heater. Therefore, good combustion practices are technically feasible for the proposed dew point heater.

5.5.5.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices and low sulfur fuels are the only remaining technically feasible technologies for controlling SO_2 emissions. Therefore, a ranking is not necessary to establish the top technology.

5.5.5.4 Step 4 – Evaluate Economic, Environmental and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices, including low sulfur fuels, will be implemented as part of the design and operation of the dew point heater. Therefore, economic, environmental, and/or energy impacts were not assessed in this BACT analysis.

5.5.5.5 Step 5 – Proposed BACT

A search was conducted of the RBLC database and recently permitted facilities. AEC identified two facilities with dew point heaters having a lower SO_2 emissions rate (Okeechobee Clean Energy Center and Indeck Niles, LLC). However, these facilities have not been built yet and the limits have not been demonstrated in practice.

One facility, Wildcat Point Generation Facility, has a lower limit of 0.006 lb/MMBtu than the proposed dew point heater using the same control methods of good combustion practices and use of a low sulfur fuel. These differences in emissions limit can be attributed to variations in size and manufacturer.

Therefore, AEC proposes the use of good combustion practices and exclusive use of natural gas with a sulfur content of 0.4 gr S/100 SCF, as BACT to minimize emissions of SO_2 from the dew point heater. These technologies represent the most stringent controls available for the dew point heater and will be used to achieve a SO_2 emissions limit of 0.0011 lb/MMBtu based on the assumption of 100% conversion of the sulfur in the fuel to SO_2.

A complete list of facilities with natural gas-fired dew point heaters from the RBLC is included in Table D-C-7.

5.5.6 BACT for H_2SO_4

This section presents the H_2SO_4 BACT discussion for the dew point heater. Emissions of H_2SO_4 from the dew point heater result from oxidation of sulfur contained within the fuel. While there are no post-combustion control technologies available for H_2SO_4 emissions control from small dew point heaters, a top-down BACT analysis for H_2SO_4 was performed for completeness purposes.

5.5.6.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling H_2SO_4 emissions from small dew point heaters. Good combustion practices include the use of low sulfur fuels (e.g., natural gas), as well as maintaining optimum combustion efficiency and implementing appropriate maintenance procedures. A review of the RBLC database and other recently permitted facilities indicates no other available H_2SO_4 control technologies for the dew point heater.

5.5.6.2 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices and low sulfur fuels are necessary for the operation and life-span of the proposed dew point heater and will be used with this dew point heater. Therefore, good combustion practices are technically feasible.

5.5.6.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices are technically feasible control technologies for H_2SO_4; therefore, a ranking has not been considered to establish a top technology.

5.5.6.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices will be implemented as part of the design and operation of the dew point heater. Therefore, economic, environmental, and/or energy impacts were not assessed in this BACT analysis.

5.5.6.5 Step 5 – Proposed BACT

AEC proposes to use good combustion practices and pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf as H_2SO_4 BACT for the dew point heater. A review was conducted of H_2SO_4 BACT determinations for dew point heaters, including a search of the RBLC database and a review of information concerning recently permitted facilities with dew point heaters. Greensville Power Station had a lower H_2SO_4 emissions limit of 0.0001 lb/MMBtu achieved through the use of pipeline quality natural gas. However, this limit is essentially equivalent to AEC's proposed limit of 0.000135 lb/MMBtu. Differences in the emissions limits can be attributed to different natural gas suppliers with varying sulfur contents, as well as different sizes, efficiency, and make and model of heater. Therefore, AEC proposes to use good combustion practices and proposes to use only pipeline quality natural gas with a maximum sulfur content of

0.4 gr/100 scf in order to minimize emissions of H_2SO_4 from the dew point heater. This represents the most stringent control available and will be used to achieve an H_2SO_4 emissions limit of 0.000135 lb/MMBtu for the dew point heater.

A complete list of facilities with natural gas-fired dew point heaters from the RBLC is included in Table D-C-8.

5.5.7 **BACT for GHG**

GHG emissions from the dew point heater result from oxidation of fuel carbon. This evaluation does not identify and discuss each of the five individual steps of the top-down BACT process, as CCS was determined not to be cost effective for the Project (see Section 5.3.7.4).

A review was conducted of GHG BACT determinations for dew point heaters, including a search of the RBLC database and a review of information concerning recently permitted facilities with dew point heaters. The results of the search, which can be found in Appendix D Table D-C-9, confirmed that the proposed GHG emissions limits for the dew point heater are consistent with dew point heaters at recently permitted facilities and entries in the RBLC.

The use of energy efficient design and work practices will be used to minimize GHG emissions. Emissions from the dew point heater will be included in an annual Facility-wide GHG limit calculated on a 12-month rolling average which can be found in Table 5-17. The CO_2e emissions from the dew point heater will be monitored by monitoring fuel use and using fuel specific emissions factors (e.g. AP-42 Table 1.4-2 for CO_2, CH_4, and N_2O) to calculate total CO_2e on a 12-month rolling basis.

5.6 CONTROL TECHNOLOGY ANALYSIS FOR THE EMERGENCY GENERATOR

This section presents the BACT determination process for the proposed ULSD-fired emergency generator engine for H_2SO_4, CO, PM, PM_{10}, $PM_{2.5}$, SO_2 and GHG and LAER determination for NO_X and VOC.

Table 5-26 presents a summary of the proposed BACT limits for the emergency generator engine.

Table 5-26
Proposed BACT and LAER for the Emergency Generator Engine
Invenergy LLC – Allegheny Energy Center

Pollutant[(a)]	BACT	Fuel	Proposed Emissions Limit	Emissions Limit Units
NO_X	Good combustion practices, low sulfur fuel, proper maintenance, and limited operation	ULSD	4.56	g/hp-hr
			30.74	lb/hr
CO	Good combustion practices, low sulfur fuel, proper maintenance, and limited operation	ULSD	2.61	g/hp-hr
			17.6	lb/hr
VOC	Good combustion practices, low sulfur fuel, proper maintenance, and limited operation	ULSD	0.24	g/hp-hr
			1.62	lb/hr
PM	Good combustion practices, low sulfur fuel, proper maintenance, and limited operation	ULSD	0.15	g/hp-hr
			1.01	lb/hr
$PM_{2.5}/PM_{10}$	Good combustion practices, low sulfur fuel, proper maintenance, and limited operation	ULSD	0.17	g/hp-hr
			1.17	lb/hr
SO_2	Good combustion practices, low sulfur fuel, proper maintenance, and limited operation	ULSD	0.0055	g/hp-hr
			0.04	lb/hr
H_2SO_4	Good combustion practices, low sulfur fuel, and limited operation	ULSD	0.00067	g/hp-hr
			0.0045	lb/hr
GHG	Good combustion practices and limited operation	ULSD	Will comply with Facility-wide GHG emissions limit.	

(a) Emissions data will be based on vendor guarantee for certified engine.

(b) Emission limits of $PM_{2.5}/PM_{10}$ for the emergency generator engine are inclusive of the condensable portion and filterable portion of particulate. Emissions of PM for the emergency generator engine are inclusive of the filterable portion of particulate only.

5.6.1 LAER for NO_X

The Project will be subject to LAER for NO_X, because potential emissions of NOx will be greater than the 100 tpy Major Stationary Source threshold applicable to an O_3 precursor in the Northeast Ozone Transport Region. NO_X emissions from the Project are also subject to PSD review, including BACT requirements. This section demonstrates that the proposed NO_X emissions and controls meet the requirements of LAER. Because LAER requirements are at least as stringent as BACT, the LAER analysis also satisfies the BACT demonstration for NOx.

This section presents the NO_X LAER/BACT discussion for the emergency generator engine. NO_X is primarily formed by two mechanisms: (1) the combination of elemental N_2 and O_2 in the combustion air within the high temperature environment of the combustor (thermal NO_X); and (2) the oxidation of N_2 contained in the fuel (fuel NO_X). NO_X emissions from the emergency generator engine originate primarily as thermal NO_X. The rate of formation of thermal NO_X is a function of residence time and free O_2 and is exponential with peak combustion cylinder temperature.

5.6.1.1 Identification of Most Stringent State Implementation Plan Limitation in Any State

The NO_X control rules potentially applicable to emergency generators fired with ULSD were reviewed and summarized for the following states and/or AQMD in Table 5-28.

Table 5-27
NO_X Emergency Generator SIP Limitations in Other Nonattainment States
Invenergy LLC – Allegheny Energy Center

State/AQMD	Regulatory Limit	Citation
Bay Area AQMD, CA	4.8 g/bhp-hr for any engine >750 bhp certified or verified to achieve the applicable standard.	BACT Guideline Revision 7, Document Number 96.1.3 (12/22/2010)

Table 5-27
NO_X Emergency Generator SIP Limitations in Other Nonattainment States
Invenergy LLC – Allegheny Energy Center

State/AQMD	Regulatory Limit	Citation
South Coast Air Quality Management District	4.8 g/bhp-hr for NMHC + NO_X for new stationary emergency standby diesel-fired compression ignition engines > 750 bhp	Rule 1470, Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines, Table 2.
San Joaquin Valley Unified (SJVU) AQMD	Latest U.S. EPA Tier Certification level for applicable horsepower range an emergency diesel IC engine	BACT Guideline 3.1.1 Last Update: 9/10/2013
New Jersey Department of Environmental Protection	The state of the art (SOTA) emission performance levels for an emergency generator application meeting the definition found at N.J.A.C. 7:27-19.1 (emergency generator) is no auxiliary air pollution control and a VOC limit of 0.15 g/bhp-hr	State of the Art Manual for Reciprocating Internal Combustion Engines 2003
Massachusetts Department of Environmental Protection	No NO_X limit for emergency diesel IC engine.	310 CMR 7.19 – Reasonably Available Control Technology for Sources of Nitrogen Oxides
New York State Department of Environmental Conservation	No NO_X limit for emergency diesel IC engine.	6NYCRR, Chapter III, Part 227-2.4(f)(6): Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_x)
Connecticut Department of Environmental Protection	No NO_X limit for emergency diesel IC engine.	RCSA 22a-174-22 Control of Nitrogen Oxides Emissions, Table 22-1

The most stringent NMHC + NO_X emissions limitation applicable to the emergency generators identified from this review of SIPs comprising the most severe ozone nonattainment areas is 4.8 g/bhp-hr. The Tier II published emissions factor of 6.4 g/kW-hr (i.e., 4.8 g/hp-hr) is for

NO_X+NMHC. AEC assumed that NO_X emissions are 95% of this factor and VOC emissions are 5% based on "CARB Emission Factor for CI Diesel Engines - Percent HC in Relation to NMHC + NO_X" policy[56]. Therefore, AEC proposes a NO_X emissions rate of 4.56 g/hp-hr as LAER for the emergency generator engine.

5.6.1.2 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are implemented in the design of the engine. Typical design features include electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-burn fuel mix.[57] Good combustion practices are standard on new engines, and therefore have been proposed for the ULSD-fired emergency generator engines.

Selective Catalytic Reduction

SCR is a post-combustion add-on NO_X control technology placed in the exhaust stream. SCR uses NH_3 to react with NO_X in the presence of a catalyst. NH_3 reacts with NO_X to form N_2 and H_2O. The NO_X reduction reaction is effective only within a given temperature range. The optimum temperature range depends on the type of catalyst used and the flue gas composition. Optimum temperatures vary from 350 to 800°F.[58] Titanium dioxide, tungsten trioxide, or vanadium pentoxide are typical materials used for the catalyst material.

[56] Policy: CARB Emission Factors for CI Diesel Engines – Percent HC in Relation to NMHC + NO_X http://www.baaqmd.gov/~/media/files/engineering/policy_and_procedures/engines/emissionfactorsfordieselengines.pdf
[57] U.S. EPA AP-42. Chapter 3.3. Gasoline and Diesel Industrial Engines (10/96).
[58] U.S. EPA Air Pollution Control Technology Fact Sheet for SCR, EPA-452/F-03-032.

5.6.1.3 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Controls

Good combustion practices, which include combustion system design and proper operation and maintenance practices, have been applied successfully to ULSD-fire emergency generator engines and are considered technically feasible for the proposed emergency generator engine.

Selective Catalytic Reduction

SCR is not a demonstrated NOx control technology for large ULSD-fired emergency generator engines, with limited operation. SCR has been applied in base-load diesel engine applications where engines are operated primarily at high capacity for extended periods of time for industrial and power generation purposes, such as "demand response" or "peak shaving" programs with revenue incentives. Based upon a review of the RBLC and recently permitted facilities, existing permits for similar sized engines, vendor information and technical literature, no specific controls, including SCR, were identified for emergency generator engines operating less than 100 hours/12-month rolling period. SCR effectiveness is limited in applications requiring quick startups and short operating durations, such as emergency use. Therefore, the application of SCR technology can be considered to be "limited" for the emergency generator engine.

5.6.1.4 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only feasible full-time control technology for the ULSD-fired emergency generator engine is good combustion practices. Due to the intermittent use of the emergency generator and the unknown duration of usage, SCR is not being considered as a practical control technology despite the fact that SCR is technically feasible. Therefore, a ranking has not been considered to establish a top technology.

5.6.1.5 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices will be implemented as part of the design and operation of the emergency generator engine. Therefore, economic, environmental, and/or energy impacts were not assessed.

5.6.1.6 Step 5 – Proposed LAER/BACT

A review was conducted for NO_X LAER/BACT determinations for emergency generator engines, including a search of the RBLC database and a review of information concerning recently permitted facilities with emergency generator engines. Some of the ULSD-fired emergency generators that were reviewed from the RBLC and recently permitted facilities have variable hourly NO_X emissions rates. However, the majority of engines are complying with the published Tier II emission standard of 6.4 g/kW-hr (i.e., 4.8 g/hp-hr), as proposed by AEC. A complete list of facilities with emergency generators from the RBLC is included in Table D-D-1.

AEC proposes good combustion practices, including the use of ULSD, and limited annual operating hours as LAER/BACT for the emergency generator engine. The Tier II published emissions factor of 6.4 g/kW-hr (i.e., 4.8 g/hp-hr) is for NO_X+NMHC. AEC followed regulatory guidance to apportion NO_X emissions as 95% of this factor and VOC emissions as 5% based on "CARB Emission Factor for CI Diesel Engines - Percent HC in Relation to NMHC + NO_X" policy[59]. Therefore, AEC proposes a NO_X emissions rate of 4.56 g/hp-hr as LAER for the emergency generator engine.

[59] Policy: CARB Emission Factors for CI Diesel Engines – Percent HC in Relation to NMHC + NO_X
http://www.baaqmd.gov/~/media/files/engineering/policy_and_procedures/engines/emissionfactorsfordieselengines.pdf

5.6.2 **BACT for CO**

This section presents the CO BACT discussion for the emergency generator engine. CO emissions are a result of incomplete combustion of carbon contained within the fuel. Properly designed and operated engines typically emit low levels of CO. High levels of CO emissions could result from poor design or sub-optimal firing conditions.

5.6.2.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are implemented in the design of the engine. Typical design features include electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-burn fuel mix.[60] Good combustion practices are standard on new engines, and therefore have been proposed for the ULSD-fired emergency generator engine.

Diesel Oxidation Catalyst

A diesel oxidation catalyst (DOC) is an add-on control technology designed to reduce CO emissions and other emissions (i.e., VOC). The DOCs are usually made of a precious metal and operate at temperatures in the range of 650 to 1,000°F.[61] The catalysts cause excess O_2 to react with CO to form CO_2. The catalytic oxidizer can be susceptible to poisoning by heavy metals and lubricating oils in the exhaust gas, which can reduce the catalyst's effectiveness.

[60] U.S. EPA AP-42. Chapter 3.3. Gasoline and Diesel Industrial Engines (10/96).
[61] Catalytic Oxidizer. *Technology Transfer Network Clearinghouse for Inventories & Emissions Factors.* http://cfpub.epa.gov/oarweb/mkb/contechnique.cfm?ControlID=10

5.6.2.2 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices, which include combustion system design and proper operation and maintenance practices, have been applied successfully to ULSD engines and are considered technically feasible for the proposed emergency generator engine.

Diesel Oxidation Catalyst

DOC is not considered to be technically feasible control option due to the smaller size of the emergency generator engine and its intermittent operations. The engine will only operate a few hours each month for readiness testing and maintenance checks and will be permitted to operate for no more than 100 hours/12-month rolling period. Therefore, this control technology is not considered further in this analysis.

5.6.2.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only feasible control technology for the ULSD-fired emergency generator engine is good combustion practices. A review of BACT determinations for CO emissions from emergency generator engines shows that good combustion practices are the only technology considered technically feasible. Therefore, a ranking has not been considered to establish a top technology.

5.6.2.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices will be implemented as part of the design and operation of the emergency generator engine. Therefore, economic, environmental, and/or energy impacts were not assessed.

5.6.2.5 Step 5 – Proposed BACT

A review was conducted of CO BACT determinations for emergency generator engines, including a search of the RBLC database and a review of information concerning recently permitted facilities with emergency generator engines.

Some facilities (St. James Methanol Plant, St. Charles Power Station, Oregon Clean Energy Center, Energy Answers Arecibo Puerto Rico Renewable Energy Project, Flopam Inc. Facility, Hess Newark Energy Center, Salem Harbor Station Redevelopment, Cove Point LNG Terminal, ENI - Holy Cross Drilling Project, Harrah's Operating Company, Inc., Ohio River Clean Fuels, LLC, Chouteau Power Plant, and Ml 35 LLC Phila Cybercenter) have a lower lb/hr (0.03 lb/hr – 17.35 lb/hr) emissions limit, but have a higher or equivalent g/hp-hr emissions limit than what is proposed by AEC. For example, the Hess Newark Energy Center has a lower lb/hr emissions limit than what is proposed, but it utilizes the same Tier II emissions limit of 3.5g/kW-hr (i.e., 2.61 g/hp-hr). Since the resulting CO mass emissions rates from an emergency generator engine are based on the BACT g/hp-hr emissions limit, the CO mass rate limits should not be used for comparison purposes.

Several facilities (MGM Mirage, Hess Newark Energy Center, Lake Charles Gasification Facility, Mid American Steel Rolling Mill, Sake Prospect Drilling Project, Nearman Creek Power Station, Creole Trail LNG Import Terminal, Fairbault Energy Park, Woodbridge Energy Center, Merck & Co. West Point, Moxie Liberty LLC/ Asylum Power Plant, GP Allendale LP, and GP Clarendon LP) have a more stringent CO emissions limit when compared to the 2.6 g/hp-hr emissions limit proposed by AEC. However, with the exception of Sake, none of the facilities are using control technologies, and therefore the difference in emissions limits can be attributed to different engine manufacturers, makes, and model years.

In addition, AEC understands that several facilities (Lake Charles Methanol Facility, Grayling Particleboard, and Hickory Run Energy Station) have lower proposed emissions limits; however, they have yet to be built, and therefore have yet to demonstrate their emissions limit in practice.

A complete list of facilities with emergency generators from the RBLC is included in Table D-D-2.

AEC proposes good combustion practices, including the use of ULSD, and limited annual operating hours as BACT for the emergency generator engine. Therefore, AEC proposes a CO emissions rate of 2.6 g/hp-hr as BACT for the emergency generator engine.

5.6.3 LAER for VOC

The Project will be subject to LAER for VOC, because estimated potential emissions of VOC from the Project will be greater than the 50 tpy Major Stationary Source threshold applicable to O_3 precursor VOC emissions in the Northeast OTR. VOC emissions from the Project are also subject to PSD review, including BACT requirements. This section demonstrates that the proposed VOC emissions and controls meet the requirements of LAER. Because LAER requirements are at least as stringent as BACT, the LAER analysis also satisfies the BACT demonstration for VOC.

This section presents the VOC LAER discussion for the emergency generator engine. VOC emissions are a result of incomplete combustion of carbon contained within the fuel. Properly designed and operated engines typically emit low levels of VOC. High levels of VOC emissions could result from poor design or sub-optimal firing conditions.

5.6.3.1 Identify the Most Stringent State Implementation Plan Limitation in Any State

The VOC control rules potentially applicable to emergency generators fired with ULSD were reviewed and summarized for the following states and/or AQMD in Table 5-28.

Table 5-28
VOC Emergency Generator SIP Limitations in Other Nonattainment States
Invenergy LLC – Allegheny Energy Center

State/AQMD	Regulatory Limit	Citation
Bay Area AQMD, CA	4.8 g/bhp-hr for any engine >750 bhp certified or verified to achieve the applicable standard.	BACT Guideline Revision 7, Document Number 96.1.3 (12/22/2010)
South Coast Air Quality Management District	4.8 g/bhp-hr for NMHC + NO_X for new stationary emergency standby diesel-fired compression ignition engines > 750 bhp	Rule 1470, Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines, Table 2.
San Joaquin Valley Unified (SJVU) AQMD	Latest U.S. EPA Tier Certification level for applicable horsepower range an emergency diesel IC engine	BACT Guideline 3.1.1 Last Update: 9/10/2013
New Jersey Department of Environmental Protection	The state of the art (SOTA) emission performance levels for an emergency generator application meeting the definition found at N.J.A.C. 7:27-19.1 (emergency generator) is no auxiliary air pollution control and a VOC limit of 0.15 g/bhp-hr	State of the Art Manual for Reciprocating Internal Combustion Engines 2003
Massachusetts Department of Environmental Protection	No VOC limit for emergency diesel IC engine.	310 CMR 7.18 – Reasonably Available Control Technology for Sources of Nitrogen Oxides
New York State Department of Environmental Conservation	No VOC limit for emergency diesel IC engine.	6NYCRR, Chapter III, Part 227-2.4(f)(6): Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_x)
Connecticut Department of Environmental Protection	No VOC limit for emergency diesel IC engine.	RCSA 22a-174-22 Control of Nitrogen Oxides Emissions, Table 22-1

The most stringent VOC emissions limitation applicable to the emergency generators identified from this review of SIPs comprising the most severe ozone nonattainment areas is 0.15 g/bhp-hr.

However, per NJDEP's SOTA Manual 13, "SOTA for an emergency generator application meeting the definition found at N.J.A.C. 7:27- 19.1, "emergency generator," is no auxiliary air pollution control." NJDEP's SOTA Manual 13 was published in 2003, which pre-dates NSPS Subpart IIII Tier certification methods. The Tier II published emissions factor of 6.4 g/kW-hr (i.e., 4.8 g/hp-hr) is for NOX+NMHC. AEC assumed that NO_X emissions are 95% of this factor and VOC emissions are 5% based "CARB Emission Factor for CI Disel Engines - Percent HC in Relation to NMHC + NO_X" policy[62]. The emergency generators will comply with the applicable 40 CFR Part 60 Subpart IIII NO_X + NMHC emissions limit by proposing 0.24 g/hp-hr VOC limit.

5.6.3.2 Step 1 - Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are implemented in the design of the engine. Typical design features include electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-burn fuel mix.[63] Good combustion practices are standard on new engines, and therefore have been proposed for the ULSD-fired emergency generator engines.

Non-Selective Catalytic Reduction (NSCR)

Similar to automobile catalytic converters, this method employs noble metal catalysts to oxidize NO_X to molecular nitrogen. It operates in regimes with less than 0.5% O_2 in the exhaust, which corresponds to fuel-rich operation. NSCR can simultaneously reduce NOx, CO, and hydrocarbons (i.e., VOC). This method is not feasible with lean-burn engines.

Oxidation Catalyst

Catalytic oxidation is an add-on control technology designed to reduce VOC and CO emissions. The catalysts are usually made of a precious metal and operate at temperatures in the range of

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[62] Policy: CARB Emission Factors for CI Diesel Engines – Percent HC in Relation to NMHC + NO_X
http://www.baaqmd.gov/~/media/files/engineering/policy_and_procedures/engines/emissionfactorsfordieselengines.pdf
[63] U.S. EPA AP-42. Chapter 3.3. Gasoline and Diesel Industrial Engines (10/96).

650°F to 1,000°F.[64] The catalytic oxidizer can be susceptible to poisoning by fine particles in the exhaust gas, thereby reducing effectiveness.

5.6.3.3 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Controls

Good combustion practices, which include combustion system design and proper operation and maintenance practices, have been applied successfully to ULSD engines and are considered technically feasible for the proposed emergency generator engine.

Non-Selective Catalytic Reduction (NSCR)

NSCR is not considered to be technically feasible due to the intermittent operations of the emergency generator engines. The emergency generator engine will only operate a few hours each month for readiness testing and maintenance checks and will be permitted to operate for no more than 100 hours/12-month rolling period total. Therefore, this control technology is not considered further in this analysis.

Oxidation Catalyst

Catalytic oxidation is not considered to be technically feasible due to the intermittent operations of the emergency generator engine. Except for the possibility of emergencies, the emergency generator engine will only operate a few hours each month for readiness testing and maintenance checks and would be permitted to run for no more than 100 hours/12-month rolling period. The catalysts are usually made of a precious metal and operate at high temperatures. In addition, issues with catalytic oxidation include the susceptibility to catalyst poisoning by fine particles in the exhaust gas, thereby reducing the catalyst effectiveness. For these reasons, it is not a technically feasible control technology for the emergency generator engine and is not considered further in

[64] Catalytic Oxidizer. *Technology Transfer Network Clearinghouse for Inventories & Emissions Factors.* http://cfpub.epa.gov/oarweb/mkb/contechnique.cfm?ControlID=10

this analysis.

5.6.3.4 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only feasible control technology for the ULSD-fired emergency generator engine is good combustion practices. A review of BACT determinations for VOC emissions from emergency generator engines shows that good combustion practices are the only technology considered technically feasible. Therefore, a ranking has not been considered to establish a top technology.

5.6.3.5 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices will be implemented as part of the design and operation of the emergency generator engine. Therefore, economic, environmental, and/or energy impacts were not assessed.

5.6.3.6 Step 5 – Proposed LAER

A review was conducted of VOC LAER determinations for emergency generator engines, including a search of the RBLC database and a review of information concerning recently permitted facilities with emergency generator engines.

Some of the ULSD-fired emergency generators that were reviewed from the RBLC and recently permitted facilities have variable hourly VOC emissions rates. However, the majority of engines are complying with the published Tier II emission standard of 6.4 g/kW-hr (i.e., 4.8 g/hp-hr), as proposed by AEC. Since the resulting VOC mass emissions rates from an emergency generator engine are based on a LAER g/hp-hr emissions limit, the VOC mass rate limits for those facilities are irrelevant.

Several facilities (Holbrook Compressor Station, Point Thomson Production Facility, Tate & Lyle Ingredients Americas, Inc., Sake Prospect Drilling Project, Creole Trail LNG Import Terminal, Fairbault Energy Park, Woodbridge Energy Center, St. Joseph Energy Center, LLC, LLC, MGM

Mirage, Ohio River Clean Fuels, LLC, Chouteau Power Plant, Moxie Liberty LLC/Asylum Power Plant, and Peony Chemical Manufacturing Facility) have a more stringent VOC emissions limit when compared to the 0.24 g/hp-hr emissions limit proposed by AEC. However, none of the facilities are using control technologies, and therefore the differences in emissions limits can be attributed to different engine manufacturers, makes, and model years.

A complete list of facilities with emergency generators from the RBLC is included in Table D-D-3.

AEC proposes good combustion practices, including the use of ULSD, and limited annual operating hours as LAER for the emergency generator engine. The Tier II published emissions factor of 6.4 g/kW-hr (i.e., 4.8 g/hp-hr) is for NO_X+NMHC. AEC assumed that NO_X emissions are 95% of this factor and VOC emissions are 5% based "CARB Emission Factor for CI Diesel Engines - Percent HC in Relation to NMHC + NO_X" policy[65]. Therefore, AEC proposes a VOC emissions rate of 0.24 g/hp-hr as BACT for the emergency generator engine.

5.6.4 **BACT for PM, PM_{10}, and $PM_{2.5}$**

This section presents the PM, PM_{10}, and $PM_{2.5}$ BACT discussion for the proposed ULSD-fired emergency generator engine. PM emissions can result from the combustion of ULSD fuel in the emergency generator engine. Smoke in the exhaust is an indicator of PM emissions. U.S. EPA identifies two types of smoke that may be emitted from ULSD-fired engines during stable operations (i.e., blue smoke and black smoke). Per U.S. EPA AP-42 Section 3.3, blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion cylinder and is partially burned. The primary constituent of black smoke is agglomerated carbon particles (soot) formed in regions of the combustion zone where mixtures are O_2 deficient. The type of smoke is

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[65] Policy: CARB Emission Factors for CI Diesel Engines – Percent HC in Relation to NMHC + NO_X
http://www.baaqmd.gov/~/media/files/engineering/policy_and_procedures/engines/emissionfactorsfordieselengines.pdf

noted throughout this discussion as it is relevant to the control practices proposed and the PM emissions that can be mitigated.

5.6.4.1 Step 1 – Identify Available Control Technologies

The following control options are evaluated in the BACT analysis.

Good Combustion Practices

Carbon soot is formed in regions of the combustion mixture that are O_2 deficient. Good combustion practices, which includes optimization of the combustion cylinder design and operation practices that improve the oxidation process and minimize incomplete combustion, are the primary mechanism available for lowering carbon soot formation. Good combustion system design, which includes continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent high temperatures in the combustion cylinder are standard features of modern engines.

Blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion cylinder and is partially burned. Per U.S. EPA AP-42 Section 3.3, proper maintenance is the most effective method of preventing blue smoke emissions from all types of engines.

Add-On Control Technologies

Modern engine designs include good combustion controls and therefore the uncontrolled PM emissions are very low. Based on the review of the RBLC database and recently permitted facilities, no emergency generator engines have been permitted with add-on PM controls, such as diesel particulate filters (DPF). Therefore, no add-on controls are considered for the proposed emergency generator engine.

5.6.4.2 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices, including combustion system design as well as proper operation and maintenance practices, are essential for the operation and life-span of the proposed emergency generator engine, and will be used with this emergency generator engine. Therefore, good combustion practices are technically feasible.

5.6.4.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only feasible control for the emergency generator engine is good combustion practices. A review of BACT determinations for PM, PM_{10}, and $PM_{2.5}$ emissions from emergency generator engines shows that good combustion practices are the only technology considered technically feasible. Therefore, a ranking has not been considered to establish a top technology.

5.6.4.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices will be implemented as part of the design and operation of the emergency generator engine. Therefore, economic, environmental, and/or energy impacts were not assessed.

5.6.4.5 Step 5 – Proposed BACT

The same control techniques are used to limit emissions of PM, PM_{10}, and $PM_{2.5}$ from the ULSD-fired emergency generator engine, and AEC has presented a combined BACT analysis for PM, PM_{10}, and $PM_{2.5}$.

PM/PM_{10}/$PM_{2.5}$

A review was conducted of PM BACT determinations for emergency generator engines, including a search of the RBLC database and a review of information concerning recently permitted facilities with emergency generator engines.

Some of the ULSD-fired emergency generators that were reviewed from the RBLC and recently permitted facilities have variable hourly $PM/PM_{10}/PM_{2.5}$ emissions rates. However, the majority of engines are complying with the published Tier II emission standard of 0.15 g/hp-hr, as proposed by AEC. Since the resulting $PM/PM_{10}/PM_{2.5}$ mass emissions rates from an emergency generator engine are based on a LAER g/hp-hr emissions limit, the $PM/PM_{10}/PM_{2.}$ mass rate limits for those facilities are irrelevant. Differences in emissions limits can be attributed to different engine manufacturers, makes, and model years.

Two facilities had a much lower limit than what is proposed by AEC (International Station Power Plant and Cornell Combined Heat and Power Project). However, given the expected limited hours of operation for the emergency generator engine, the decrease in PM emissions if the engine were required to achieve those lower limits would be negligible. Differences in emissions limits can be attributed to different engine manufacturers, makes, and model years.

AEC proposes good combustion practices, limited annual operating hours and proper maintenance as BACT for the emergency generator engine. Therefore, AEC proposes complying with the NSPS Subpart IIII Tier II PM emissions rate of 0.15 g/hp-hr and a $PM_{10}/PM_{2.5}$ emissions rate of 0.17 g/hp-hr that conservatively includes condensable PM as BACT for the emergency generator engine.

A complete list of facilities with emergency generators from the RBLC is included in Table D-D-4, Table D-D-5, and Table D-D-6.

5.6.5 **BACT for SO_2**

This section presents the SO_2 BACT discussion for the emergency generator engine. SO_2 results from the oxidation of fuel sulfur. SO_2 is formed when sulfur contained in the fuel is burned, combining with O_2 in the combustion air to create SO_2. The applicable diesel fuel sulfur content specified by NSPS Subpart IIII is 15 ppm. ACHD Article XXI §2104.10 limits No. 2 oil sulfur content to 0.05%. The sulfur content of the ULSD fuel to be used in the emergency engines (15 ppm or 0.0015%) will comply with both standards.

5.6.5.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are implemented in the design of the engine. Typical design features include electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-burn fuel mix.[66] Good combustion practices are standard on new engines, and therefore have been proposed for the ULSD-fired emergency generator engine.

Scrubber/Flue Gas Desulfurization

A scrubber (or desulfurization unit) is a control technology used to abate SO_2 emissions. Scrubbers use chemical and mechanical processes to remove SO_2 from the gas. However, according to a search of recently permitted facilities and the RBLC database, there are currently no emergency generator engines that employ this technology. Therefore, scrubbers are not considered "available" for these sources.

5.6.5.2 Step 2 – Eliminate Technically Infeasible Options

Good combustion practices, including the use of low sulfur fuels, are essential for the operation and life-span of the emergency generator engine. Therefore, good combustion practices are technically feasible for the emergency generator engine.

[66] U.S. EPA AP-42. Chapter 3.3. Gasoline and Diesel Industrial Engines (10/96).

5.6.5.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices and low sulfur fuels are the only remaining technically feasible technologies for controlling SO_2 emissions. Therefore, a ranking is not necessary to establish the top technology.

5.6.5.4 Step 4 – Evaluate Economic, Environmental and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices, including low sulfur fuels, will be implemented as part of the design and operation of the emergency generator engine. Therefore, economic, environmental, and/or energy impacts were not assessed in this BACT analysis.

5.6.5.5 Step 5 – Proposed BACT

A review was conducted of SO_2 BACT determinations for emergency generator engines, including a search of the RBLC database and a review of information concerning recently permitted facilities with emergency generator engines.

One facility (Garyville Refinery) has a lower lb/hr emissions rate but has a higher g/hp-hr emissions limit than what is proposed by AEC. Since the resulting SO_2 mass emissions rates from an emergency generator engine are based on a BACT g/hp-hr emissions limit, the mass rate SO_2 limit is irrelevant.

Several facilities (Greensville Power Station, St. Joseph Energy Center, LLC, Lake Charles Gasification Facility, Salem Harbor Station Redevelopment, and Oregon Clean Energy Center) has a more stringent SO_2 emissions limit when compared to the 0.0055 g/hp-hr emissions limit proposed by AEC. However, none of the facilities are using control technologies, and therefore the differences in emissions limits can be attributed to different engine manufacturers, makes, and model years.

AEC proposes good combustion practices, proper maintenance, limited annual operating hours, and the exclusive use of ULSD with a sulfur content of 15 ppm to minimize emissions of SO_2 from the emergency diesel engine, which represents the most stringent controls available for this equipment. The proposed SO_2 emission limit is 0.0055 g/hp-hr, based on the assumption of 100 percent conversion of the sulfur in the fuel to SO_2.

A complete list of facilities with emergency generators from the RBLC is included in Table D-D-7.

5.6.6 BACT for H_2SO_4

Emissions of H_2SO_4 from the emergency generator engine results from oxidation of sulfur contained within the fuel. While there are no post-combustion control technologies available for H_2SO_4 emissions control from engines, a top-down BACT analysis for H_2SO_4 was performed for completeness purposes.

5.6.6.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling H_2SO_4 emissions from emergency generator engines. Good combustion practices include the use of ULSD with a maximum sulfur content of 0.0015 weight percent (15 ppmw), as well as maintaining optimum combustion efficiency and implementing appropriate maintenance procedures. A review of the RBLC database and other recently permitted facilities indicates no other available H_2SO_4 control technologies for the emergency generator engine.

5.6.6.2 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices and low sulfur fuels are necessary for the operation and life-span of the proposed emergency generator engine and will be used with this emergency generator engine. Therefore, good combustion practices are technically feasible.

5.6.6.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices, including the use of low sulfur fuels, are a technically feasible control technology for H_2SO_4 for the emergency generator engine. Therefore, a ranking to establish the top control technology has not been considered.

5.6.6.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices, including the use of low sulfur fuels, will be implemented as part of the operation of the emergency generator engine. Therefore, economic, environmental, and/or energy impacts were not assessed in this BACT analysis.

5.6.6.5 Step 5 – Proposed BACT

As mentioned in Section 5.6.5, the allowable diesel fuel sulfur content specified by 40 CFR Part 60 Subpart IIII is 15 ppmw (i.e., 0.0015%). In addition, the diesel fuel sulfur content specified in § 2104.10 limits the sulfur content of No. 2 oil to 0.5%, which is less stringent. The sulfur content of the ULSD to be used in the emergency generator engine will comply with the more stringent NSPS requirements.

AEC reviewed the RBLC database and other recently permitted facilities and identified several emergency generator engines (Belle River Combined Cycle Power Plant, Greensville Power Station, Salem Harbor Station Redevelopment and Cornell Combined Heat & Power Project) with lower proposed H_2SO_4 limits. Belle River Combined Cycle Power Plant is still being constructed, thus their limits have not been demonstrated. The Cornell Combined Heat & Power Project has a lower lb/hr emissions limit, but also has a higher g/hp-hr emissions limit than what is proposed by AEC. Since the resulting H_2SO_4 mass emissions rates from an emergency generator engine are based on applying the g/hp-hr emissions limit, the H_2SO_4 limit for the Cornell Facility does not reflect a more stringent limit than for the proposed emergency generator engine.

A complete list of facilities with emergency generators from the RBLC is included in Table D-D-8.

AEC proposes to use good combustion practices and to exclusively use ULSD to minimize emissions of H_2SO_4 from the emergency generator engine. This approach represents the best method for controlling H_2SO_4 emissions and will be used to achieve an H_2SO_4 emissions limit of 0.00067 g/hp-hr for the emergency generator engine. This proposed emissions limit is based on the sulfur content of the fuel, full load operation, 100% of the sulfur in the fuel is converted to SO_2, 10% of the SO_2 is converted to SO_3, and 100% conversion of SO_3 to H_2SO_4.

5.6.7 BACT for GHG

GHG emissions from the emergency generator engine result from oxidation of fuel carbon. This evaluation does not identify and discuss each of the five individual steps of the top-down BACT process, as CCS was determined not to be cost effective for the Project (see Section 5.3.7).

A review was conducted of GHG BACT determinations for emergency generator engines, including a search of the RBLC database and a review of information concerning recently permitted facilities with emergency generator engines. The results of the search, which can be found in Appendix D Table D-D-9, confirmed that the proposed GHG emissions limits for the emergency generator engine are consistent with emergency generator engines at recently permitted facilities and entries in the RBLC.

The use of energy efficient design and work practices will be used to minimize GHG emissions. Emissions from the emergency generator engine will be included in an annual Facility-wide limit calculated on a 12-month rolling average which can be found in Table 5-17.

5.7 CONTROL TECHNOLOGY ANALYSIS FOR THE FIRE WATER PUMP ENGINE

This section presents the BACT determination process for the proposed fire water pump engine for H_2SO_4, CO, PM, PM_{10}, $PM_{2.5}$, SO_2 and GHG and LAER determinations for NO_X and VOC.

Table 5-29 presents a summary of the proposed BACT and LAER limits for the fire water pump engine.

Table 5-29
Proposed BACT and LAER for the Fire Water Pump Engine
Invenergy LLC – Allegheny Energy Center

Pollutant[a]	BACT	Fuel	Proposed Emissions Limit	Emissions Limit Units
NO_X	Good combustion practices, low sulfur fuel, and limited operating hours	ULSD	2.85	g/hp-hr
			1.77	lb/hr
CO	Good combustion practices, low sulfur fuel, and limited operating hours	ULSD	2.60	g/hp-hr
			1.62	lb/hr
VOC	Good combustion practices, low sulfur fuel, and limited operating hours	ULSD	0.15	g/hp-hr
			0.09	lb/hr
PM	Good combustion practices, low sulfur fuel, and limited operating hours	ULSD	0.15	g/hp-hr
			0.09	lb/hr
$PM_{2.5}/PM_{10}$	Good combustion practices, low sulfur fuel, and limited operating hours	ULSD	0.17	g/hp-hr
			0.11	lb/hr

Table 5-29
Proposed BACT and LAER for the Fire Water Pump Engine
Invenergy LLC – Allegheny Energy Center

Pollutant[a]	BACT	Fuel	Proposed Emissions Limit	Emissions Limit Units
SO_2	Good combustion practices, low sulfur fuel, and limited operating hours	ULSD	0.93	g/hp-hr
			0.578	lb/hr
H_2SO_4	Good combustion practices, low sulfur fuel, and limited operating hours	ULSD	0.114	g/hp-hr
			0.07	lb/hr
GHG	Good combustion practices and limited operation	ULSD	Will comply with Project-wide GHG emissions limit.	

(a) Emissions data will be based on vendor guarantee for certified engine.

(b) Emissions limits of $PM_{2.5}/PM_{10}$ for the fire water pump engine are inclusive of the condensable portion and filterable portion of particulate. The emissions limit for PM for the fire water pump engine is inclusive of the filterable portion of particulate only.

5.7.1 LAER for NO_X

The Project will be subject to LAER for NO_X, because estimated potential emissions of NOx will be greater than the 100 tpy Major Stationary Source threshold applicable to an O_3 precursor in the Northeast Ozone Transport Region. NO_X emissions from the Project are also subject to PSD review, including BACT requirements. This section demonstrates that the proposed NO_X emissions and controls meet the requirements of LAER. Because LAER requirements are at least as stringent as BACT, the LAER analysis also satisfies the BACT demonstration for NOx.

This section presents the NO_X LAER discussion for the fire water pump engine. NO_X is primarily formed by two mechanisms: the combination of elemental N_2 and O_2 in the combustion air within the high temperature environment of the combustor (thermal NO_X); and the oxidation of N_2 contained in the fuel (fuel NO_X). NO_X emissions from the fire water pump engine originate primarily as thermal NO_X. The rate of formation of thermal NO_X is a function of residence time and free O_2 and is exponential with peak flame temperature.

5.7.1.1 Identification of Most Stringent State Implementation Plan Limitation in Any State

The NO_X control rules potentially applicable to a fire water pump fired with ULSD were reviewed and summarized for the following states and/or AQMD in Table 5-30

Table 5-30
NO_X Fire Water Pump SIP Limitations in Other Nonattainment States
Invenergy LLC – Allegheny Energy Center

State/AQMD	Regulatory Limit	Citation
Bay Area AQMD, CA	3.0 g/bhp-hr for NMHC + NO_X for stationary emergency standby diesel fueled CI engines 300 ≤ bhp ≤ 600	BACT Guideline Revision 7, Document Number 96.1.3 (12/22/2010)
South Coast Air Quality Management District	3.0 g/bhp-hr for NMHC + NO_X for new stationary emergency standby diesel fueled direct-drive fire pump engines 175 ≤ bhp ≤ 750.	Rule 1470, Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines, Table 3.
San Joaquin Valley Unified (SJVU) AQMD	Latest U.S. EPA Tier Certification level for applicable horsepower range an emergency diesel IC engine	BACT Guideline 3.1.1 Last Update: 9/10/2013
New Jersey Department of Environmental Protection	The state of the art (SOTA) emission performance levels for an emergency generator application meeting the definition found at N.J.A.C. 7:27-19.1 (emergency generator) is no auxiliary air pollution control.	State of the Art Manual for Reciprocating Internal Combustion Engines 2003
Massachusetts Department of Environmental Protection	No specific NO_X limit for emergency diesel fire water pumps.	310 CMR 7.19 – Reasonably Available Control Technology for Sources of Nitrogen Oxides

Table 5-30
NO_X Fire Water Pump SIP Limitations in Other Nonattainment States
Invenergy LLC – Allegheny Energy Center

State/AQMD	Regulatory Limit	Citation
New York State Department of Environmental Conservation	No specific NO_X limit for emergency diesel fire water pumps.	6NYCRR, Chapter III, Part 227-2.4: Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_x)
Connecticut Department of Environmental Protection	No specific NO_X limit for emergency diesel fire water pumps.	RCSA 22a-174

The unit will be operated only during emergency situations, routine maintenance and readiness testing, and will comply with the applicable emissions limits of 40 CFR Subpart IIII Table 4 of 3.0 g/hp-hr for NO_X+NMHC. Invenergy assumed that NO_X emissions are 95% of this factor and VOC emissions are 5% based on "CARB Emission Factor for CI Diesel Engines - Percent HC in Relation to NMHC + NO_X" policy[67]. The emergency generators will comply with the applicable 40 CFR Part 60 Subpart IIII NO_X + NMHC emissions limit by proposing 2.85 g/hp-hr as LAER.

5.7.1.2 Step 1 – Identify Available Control Technologies

The available control technologies for a fire water pump engine have been identified for typical engines with limited or emergency operations. The potentially available control technologies for reducing NO_X emissions from a fire water pump engine include combustion controls, SCR and NSCR.

[67] Policy: CARB Emission Factors for CI Diesel Engines – Percent HC in Relation to NMHC + NO_X
http://www.baaqmd.gov/~/media/files/engineering/policy_and_procedures/engines/emissionfactorsfordieselengines.pdf

Good Combustion Practices

Good combustion practices are implemented in the design of the engine. Typical design features include electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-burn fuel mix.[68] Good combustion practices are standard on new engines, and therefore have been proposed for the ULSD-fired fire water pump engine.

Selective Catalytic Reduction

SCR is a post-combustion add-on NO_X control technology placed in the exhaust stream. SCR uses NH_3 to react with NO_X in the presence of a catalyst. NH_3 reacts with NO_X to form N_2 and H_2O. The NO_X reduction reaction is effective only within a given temperature range. The optimum temperature range depends on the type of catalyst used and the flue gas composition. Optimum temperatures vary from 480 to 800°F.[69] Titanium dioxide, tungsten trioxide, or vanadium pentoxide are typical materials used for the catalyst material.

5.7.1.3 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Controls

Good combustion practices, which include combustion system design and proper operation and maintenance practices, have been applied successfully to ULSD engines and are considered technically feasible for the proposed fire water pump engine.

Selective Catalytic Reduction

SCR is not a demonstrated NO_X control technology for fire water pump engines. SCR has been applied in base-load diesel engine applications where engines are operated primarily at high

[68] U.S. EPA AP-42. Chapter 3.3. Gasoline and Diesel Industrial Engines (10/96).
[69] U.S. EPA Air Pollution Control Technology Fact Sheet for SCR, EPA-452/F-03-032.

capacity for extended periods of time for industrial and power generation purposes. Based upon a review of the RBLC and recently permitted facilities, no specific controls were identified for fire water pump engines operating less than 100 hours/12-month rolling period. An SCR is also not technically feasible in applications requiring quick startups and short operating durations. Therefore, the SCR technology is not considered to be technically feasible for the fire water pump engine and is not considered further in this analysis.

5.7.1.4 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only feasible control technology for the fire water pump engine is good combustion practices. A review of BACT determinations for NO_X emissions from fire water pump engines shows that good combustion practices are the only technology considered technically feasible. Therefore, a ranking has not been considered to establish a top technology.

5.7.1.5 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices will be implemented as part of the design and operation of the fire water pump engine. Therefore, economic, environmental, and/or energy impacts were not assessed.

5.7.1.6 Step 5 – Proposed LAER

A review was conducted of NO_X LAER determinations for fire water pump engine, including a search of the RBLC database and a review of information concerning recently permitted facilities with fire water pump engine.

Some of the fire water pump engines that were reviewed from the RBLC and recently permitted facilities have variable hourly NO_X emissions rates. However, the majority of engines are complying with the published 40 CFR Part 60, Subpart IIII, Table 4 standard of 4.0 g/kW-hr (i.e., 3.0 g/hp-hr), as proposed by AEC. Since the resulting NO_X mass emissions rates from the fire water pump engines are based on a comparable LAER g/hp-hr emissions limit, the NO_X mass limits for those facilities are irrelevant.

Several facilities (Methanex- Geismar Methanol Plant, Monsanto Luling Plant, Moxie Liberty LLC/Asylum Power Plant, Moxie Energy LLC/Patriot Generation Plant, CPV Valley Energy Center Wawayanda, NY, Hess Newark Energy Center, and Woodbridge Energy Center) have a more stringent NO_X emissions limit when compared to the 2.85 g/hp-hr emissions limit proposed by AEC. However, none of the facilities are using control technologies, and therefore the differences in emissions limits can be attributed to different engine manufacturers, makes, and model years.

A complete list of facilities with emergency generators from the RBLC is included in Table D-E-1.

Therefore, given that the unit will be operated only during emergency situations, routine maintenance and readiness testing, and the fact that the unit will comply with the applicable emissions limits of 40 CFR Subpart IIII Table 4 standards of 3.0 g/hp-hr for NMHC + NO_X for the fire water pump engine, AEC proposes 2.85 g/hp-hr as LAER. AEC referred to regulatory guidance to apportion NO_X emissions as 95% of the 40 CFR Subpart IIII Table 4 standard and VOC emissions as 5% based on "CARB Emission Factor for CI Diesel Engines - Percent HC in Relation to NMHC + NO_X" policy[70].

5.7.2 **BACT for CO**

This section presents the CO BACT discussion for the proposed fire water pump engine. CO emissions occur as a result of incomplete combustion of carbonaceous fuels.

[70] Policy: CARB Emission Factors for CI Diesel Engines – Percent HC in Relation to NMHC + NO_X
http://www.baaqmd.gov/~/media/files/engineering/policy_and_procedures/engines/emissionfactorsfordieselengines.pdf

5.7.2.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are implemented in the design of the engine. Typical design features include electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-burn fuel mix.[71] Good combustion practices are standard on new engines, and therefore have been proposed for the ULSD-fired fire water pump engine.

Diesel Oxidation Catalyst (DOC)

DOC is an add-on control technology designed to reduce CO emissions and other emissions (i.e., VOC). The DOCs are usually made of a precious metal and operate at temperatures in the range of 650 to 1,000°F.[72] The catalysts cause excess O_2 to react with CO to form CO_2. The catalytic oxidizer can be susceptible to poisoning by heavy metals and lubricating oils in the exhaust gas, which can reduce the catalyst's effectiveness.

5.7.2.2 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices, which include combustion system design and proper operation and maintenance practices, have been applied successfully to ULSD engines and are considered technically feasible for the proposed fire water pump engine.

Diesel Oxidation Catalyst (DOC)

DOC is not considered to be technically feasible due to the small size of the fire water pump engine

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71 U.S. EPA AP-42. Chapter 3.3. Gasoline and Diesel Industrial Engines (10/96).
72 Catalytic Oxidizer. *Technology Transfer Network Clearinghouse for Inventories & Emissions Factors.* http://cfpub.epa.gov/oarweb/mkb/contechnique.cfm?ControlID=10

and intermittent operations. The fire water pump engine will only operate a few hours each month for readiness testing and maintenance checks and is permitted to operate for no more than 100 hours/12-month rolling period total. Therefore, this control technology is not considered further in this analysis

5.7.2.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only feasible control technology for the fire water pump engine is good combustion practices. A review of BACT determinations for CO emissions from fire water pump engines shows that good combustion practices are the only technology considered technically feasible. Therefore, a ranking has not been considered to establish a top technology.

5.7.2.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices will be implemented as part of the design and operation of the fire water pump engine. Therefore, economic, environmental, and/or energy impacts were not assessed.

5.7.2.5 Step 5 – Proposed BACT

A review was conducted of CO BACT determinations for fire water pump engines, including a search of the RBLC database and a review of information concerning recently permitted facilities with fire water pump engines.

Several facilities (St. Charles Power Station, Ohio River Clean Fuels, LLC, Oregon Clean Energy Center, and Hess Newark Energy Center) have a lower lb/hr or tpy emissions rate but have an equal or higher g/hp-hr emissions limit than what is proposed by AEC. Since the resulting CO mass emissions rates from a fire water pump engine are based on the BACT g/hp-hr emissions limit, the CO mass rate limits should not be used for comparison purposes.

Several facilities (PSEG Fossil LLC Sewaren, Beaumont Terminal, Blythe Energy Project II, Avenal Energy Project, Crescent City Power, Flopam Inc. Facility, Forsyth Energy Plant, Moxie Liberty LLC/Asylum Power Plant, Moxie Energy LLC/Patriot Generation Plant, CPV Valley Energy Center Wawayanda, NY, and Astoria Energy LLC) have a more stringent CO emissions limit when compared to the 2.6 g/hp-hr emissions limit proposed by AEC. However, none of the facilities are using control technologies, and therefore the differences in emissions limits can be attributed to different engine manufacturers, makes, and model years.

In addition, AEC understands that several facilities (Donlin Gold Project, St. James Methanol Plant, Moundsville Combined Cycle Power Plant, and Cricket Valley Energy Center) have lower proposed emissions limits; however, they have yet to be built, and therefore have yet to demonstrate their emissions limit in practice.

A complete list of facilities with emergency generators from the RBLC is included in Table D-E-2.

AEC proposes good combustion practices, including the use of ULSD, and limited annual operating hours as BACT for the fire water pump. Therefore, AEC proposes a CO emissions rate of 2.60 g/hp-hr as BACT for the fire water pump engine.

5.7.3 **LAER for VOC**

The Project will be subject to LAER for VOC, because estimated potential emissions of VOC from the Project will be greater than the 50 tpy Major Stationary Source threshold applicable to O_3 precursor VOC emissions in the Northeast OTR. VOC emissions from the Project are also subject to PSD review, including BACT requirements. This section demonstrates that the proposed VOC emissions and controls meet the requirements of LAER. Because LAER requirements are at least as stringent as BACT, the LAER analysis also satisfies the BACT demonstration for VOC.

This section presents the VOC BACT discussion for the fire water pump engine. VOC emissions are a result of incomplete combustion of carbon contained within the fuel. Properly designed and operated engines typically emit low levels of VOC. High levels of VOC emissions could result from poor design or sub-optimal firing conditions.

5.7.3.1 Identify the Most Stringent State Implementation Plan Limitation in Any State

The VOC control rules potentially applicable to a fire water pump fired with ULSD were reviewed and summarized for the following states and/or AQMD in Table 5-31

Table 5-31
VOC Fire Water Pump SIP Limitations in Other Nonattainment States
Invenergy LLC – Allegheny Energy Center

State/AQMD	Regulatory Limit	Citation
Bay Area AQMD, CA	3.0 g/bhp-hr for NMHC + NO_X for stationary emergency standby diesel fueled CI engines 300 ≤ bhp ≤ 600	BACT Guideline Revision 7, Document Number 96.1.3 (12/22/2010)
South Coast Air Quality Management District	3.0 g/bhp-hr for NMHC + NO_X for new stationary emergency standby diesel fueled direct-drive fire pump engines 175 ≤ bhp ≤ 750.	Rule 1470, Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines, Table 3.
San Joaquin Valley Unified (SJVU) AQMD	Latest U.S. EPA Tier Certification level for applicable horsepower range an emergency diesel IC engine	BACT Guideline 3.1.1 Last Update: 9/10/2013
New Jersey Department of Environmental Protection	VOC limit of 0.15 g/bhp-hr	State of the Art Manual for Reciprocating Internal Combustion Engines 2003
Massachusetts Department of Environmental Protection	No specific VOC limit for emergency diesel fire water pumps.	310 CMR 7.19 – Reasonably Available Control Technology for Sources of Nitrogen Oxides

Table 5-31
VOC Fire Water Pump SIP Limitations in Other Nonattainment States
Invenergy LLC – Allegheny Energy Center

State/AQMD	Regulatory Limit	Citation
New York State Department of Environmental Conservation	No specific VOC limit for emergency diesel fire water pumps.	6NYCRR, Chapter III, Part 227-2.4: Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_x)
Connecticut Department of Environmental Protection	No specific VOC limit for emergency diesel fire water pumps.	RCSA 22a-174

The most stringent VOC emissions limitation applicable to the emergency generators identified from this review of SIPs comprising the most severe ozone nonattainment areas is 0.15 g/bhp-hr. However, per NJDEP's SOTA Manual 13, "SOTA for an emergency generator application meeting the definition found at N.J.A.C. 7:27- 19.1, "emergency generator," is no auxiliary air pollution control." NJDEP's SOTA Manual 13 was published in 2003, which pre-dates NSPS Subpart IIII Tier certification methods. The unit will be operated only during emergency situations, routine maintenance and readiness testing, and will comply with the applicable emissions limits of 40 CFR Subpart IIII Table 4 of 3.0 g/hp-hr for NO_X+NMHC. AEC assumed that NO_X emissions are 95% of this factor and VOC emissions are 5% based "CARB Emission Factor for CI Diesel Engines - Percent HC in Relation to NMHC + NO_X" policy[73]. The fire water pump engine will comply with the applicable 40 CFR Part 60 Subpart IIII Table 4 NO_X + NMHC emissions limit by proposing 0.15 g/hp-hr VOC limit.

[73] Policy: CARB Emission Factors for CI Diesel Engines – Percent HC in Relation to NMHC + NO_X
http://www.baaqmd.gov/~/media/files/engineering/policy_and_procedures/engines/emissionfactorsfordieselengines.pdf

5.7.3.2 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are implemented in the design of the engine. Typical design features include electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-burn fuel mix.[74] Good combustion practices are standard on new engines, and therefore have been proposed for the fire water pump engine.

Non-Selective Catalytic Reduction

Similar to automobile catalytic converters, this method employs noble metal catalysts to oxidize NO_X to molecular nitrogen. It operates in regimes with less than 0.5% O_2 in the exhaust, which corresponds to fuel-rich operation. NSCR can simultaneously reduce NO_X, CO, and hydrocarbons (i.e., VOC). The method is not feasible with lean-burn engines.

Oxidation Catalyst

Catalytic oxidation is an add-on control technology designed to reduce VOC emissions. The catalysts are usually made of a precious metal and operate at temperatures in the range of 650 to 1,000°F.[75] Catalytic oxidizers can be susceptible to poisoning by fine particles in the exhaust gas, which reduces the catalyst's effectiveness.

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[74] U.S. EPA AP-42. Chapter 3.3. Gasoline and Diesel Industrial Engines (10/96).

[75] Catalytic Oxidizer. *Technology Transfer Network Clearinghouse for Inventories & Emissions Factors.* http://cfpub.epa.gov/oarweb/mkb/contechnique.cfm?ControlID=10

5.7.3.3 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Controls

Good combustion practices, which include combustion system design and proper operation and maintenance practices, have been applied successfully to ULSD engines and are considered technically feasible for the proposed fire water pump engine.

Non-Selective Catalytic Reduction

NSCR is not considered to be technically feasible due to the small size of the fire water pump engine and intermittent operations. The engine will only operate a few hours each month for readiness testing and maintenance checks and will be permitted to operate for no more than 100 hours/12-month rolling period. Therefore, this control technology is not considered further in this analysis.

Oxidation Catalyst

Catalytic oxidation is not considered to be technically feasible due to the small size of the fire water pump engine and intermittent operations. The engine will only operate a few hours each month for readiness testing and maintenance checks and will be permitted to operate for no more than 100 hours/12-month rolling period. The catalysts are usually made of a precious metal and operate at high temperatures. In addition, issues with catalytic oxidation include the catalyst's susceptibility to poisoning by fine particles in the exhaust gas, which reduces the catalyst's effectiveness. For these reasons it is not a technically feasible control technology for the fire water pump engine and is not considered further in this analysis.

5.7.3.4 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only feasible control technology for the fire water pump engine is good combustion practices. A review of BACT determinations for VOC emissions from fire water pump engines shows that good combustion practices are the only technology considered technically feasible. Therefore, a ranking has not been considered to establish a top technology.

5.7.3.5 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices will be implemented as part of the design and operation of the fire water pump engine. Therefore, economic, environmental, and/or energy impacts were not assessed.

5.7.3.6 Step 5 – Proposed LAER

A review was conducted of VOC LAER determinations for fire water pump engine, including a search of the RBLC database and a review of information concerning recently permitted facilities with fire water pump engine.

Some of the fire water pump engines that were reviewed from the RBLC and recently permitted facilities have variable hourly VOC emissions rates. However, the majority of engines are complying with the published 40 CFR Part 60, Subpart IIII, Table 4 standard of 4.0 g/kW-hr (i.e., 3.0 g/hp-hr), as proposed by AEC. Since the resulting VOC mass emissions rates from the fire water pump engines are based on a comparable LAER g/hp-hr emissions limit, the NO_X mass limits for those facilities are irrelevant.

Several facilities (Baton Rouge Junction Facility, Crescent City Power, Holland Board of Public Works – East 5th Street, PSEG Fossil LLC Sewaren Generating Station, Moxie Liberty LLC/Asylum Power Plant, Moxie Energy LLC/Patriot Generation Plant, and Tenaska Partners LLC) have a more stringent VOC emissions limit when compared to the 0.15 g/hp-hr emissions limit proposed by AEC. However, none of the facilities are using control technologies, and therefore the differences in emissions limits can be attributed to different engine manufacturers, makes, and model years.

A complete list of facilities with emergency generators from the RBLC is included in Table D-E-3.

Therefore, given that the unit will be operated only during emergency situations, routine maintenance and readiness testing, and the fact that the unit will comply with the applicable emissions limits of 40 CFR Subpart IIII Table 4 standards of 3.0 g/hp-hr for NMHC + NO_X for the fire water pump engine, AEC proposes 0.15 g/hp-hr as LAER. AEC assumed that NO_X emissions are 95% of the 40 CFR Subpart IIII Table 4 standard and VOC emissions are 5% based "CARB Emission Factor for CI Diesel Engines - Percent HC in Relation to NMHC + NO_X" policy[76].

5.7.4 **BACT for PM, PM_{10}, and $PM_{2.5}$**

This section presents the PM, PM_{10}, and $PM_{2.5}$ BACT discussion for the proposed ULSD-fired fire water pump engine. PM emissions can result from the combustion of ULSD fuel in the fire water pump engine. Smoke in the exhaust is an indicator of PM emissions. U.S. EPA identifies two types of smoke that may be emitted from ULSD-fired engines during stable operations (i.e., blue smoke and black smoke). Per U.S. EPA AP-42 Section 3.3, blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion cylinder and is partially burned. The primary constituent of black smoke is agglomerated carbon particles (soot) formed in regions of the combustion zone where mixtures are O_2 deficient. The type of smoke is noted throughout this discussion as it is relevant to the control practices proposed and the PM emissions that can be mitigated.

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[76] Policy: CARB Emission Factors for CI Diesel Engines – Percent HC in Relation to NMHC + NO_X
http://www.baaqmd.gov/~/media/files/engineering/policy_and_procedures/engines/emissionfactorsfordieselengines.pdf

5.7.4.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Carbon soot is formed in regions of the combustion mixture that are O_2 deficient. Good combustion practices, which includes optimization of the combustion cylinder design and operation practices that improve the oxidation process and minimize incomplete combustion, are the primary mechanism available for lowering carbon soot formation. Good combustion system design, which includes continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent high temperatures in the combustion cylinder are standard features of modern engines.

Blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion cylinder and is partially burned. Per U.S. EPA AP-42 Section 3.3, proper maintenance is the most effective method of preventing blue smoke emissions from all types of engines.

Add-On Control Technologies

Modern engine designs include good combustion controls and, therefore, the uncontrolled PM emissions are very low. Based on a review of the RBLC database and recently permitted facilities, no fire water pump engines have been permitted with add-on PM controls, such as DPF. Therefore, no add-on controls are considered for the proposed fire water pump engine.

5.7.4.2 Step 2 – Eliminate Technically Infeasible Options

The following control technologies are evaluated in order to determine the technical feasibility of the potential control options.

Good Combustion Practices

Good combustion practices, including combustion system design as well as proper operation and maintenance practices, are essential for the operation and life-span of the proposed fire water pump engine, and will be used with this fire water pump engine. Therefore, good combustion practices are technically feasible.

5.7.4.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only feasible control technology for the fire water pump engine is good combustion practices. A review of BACT determinations for PM, PM_{10}, and $PM_{2.5}$ emissions from fire water pump engines shows that good combustion practices are the only technology considered technically feasible. Therefore, a ranking has not been considered to establish a top technology.

5.7.4.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices will be implemented as part of the design and operation of the fire water pump engine. Therefore, economic, environmental, and/or energy impacts were not assessed.

5.7.4.5 Step 5 – Proposed BACT

The same control techniques are used to limit emissions of PM, PM_{10}, and $PM_{2.5}$ from the ULSD-fired fire water pump engine, and AEC has presented a combined BACT analysis for PM, PM_{10}, and $PM_{2.5}$.

PM/PM_{10}/$PM_{2.5}$

A review was conducted of PM BACT determinations for fire water pump engines, including a search of the RBLC database and a review of information concerning recently permitted facilities with emergency generator engines.

Some of the ULSD-fired emergency generators that were reviewed from the RBLC and recently permitted facilities have variable hourly $PM/PM_{10}/PM_{2.5}$ emissions rates. However, the majority of engines are complying with the published 40 CFR Part 60, Subpart IIII, Table 4 standard of 0.15 g/hp-hr, as proposed by AEC. Since the resulting $PM/PM_{10}/PM_{2.5}$ mass emissions rates from an emergency generator engine are based on a LAER g/hp-hr emissions limit, the $PM/PM_{10}/PM_{2.}$ mass rate limits for those facilities are irrelevant. Differences in emissions limits can be attributed to different engine manufacturers, makes, and model years.

Two facilities had lower limits than what is proposed by AEC (Moxie Liberty LLC/Asylum Power Plant and Moxie Energy LLC/Patriot Generation Plant). The initial air permitting for the Moxie facilities estimated potential emissions based on a specification sheet for a sample fire pump. The air permits have not been updated to reflect the as-built equipment, and it is unknown if those lower limits have been demonstrated in practice. However, given the expected limited hours of operation for the emergency generator engine, the decrease in PM emissions if the engine were required to achieve those lower limits would be negligible. Differences in emissions limits can be attributed to different engine manufacturers, makes, and model years.

A complete list of facilities with emergency generators from the RBLC is included in Table D-E-4, Table D-E-5, and Table D-E-6.

AEC proposes good combustion practices, limited annual operating hours and proper maintenance as BACT for the fire water pump engine. Therefore, AEC proposes complying with the 40 CFR Part 60, Subpart IIII, Table 4 PM emissions rate of 0.15 g/hp-hr and a $PM_{10}/PM_{2.5}$ emissions rate of 0.17 g/hp-hr that conservatively includes condensable PM as BACT for the emergency generator engine.

5.7.5 **BACT for SO_2**

This section presents the SO_2 BACT discussion for the fire water pump engine. SO_2 results from the oxidation of fuel sulfur. SO_2 is formed when sulfur contained in the fuel is burned, combining with O_2 in the combustion air to create SO_2. The applicable diesel fuel sulfur content specified by

NSPS Subpart IIII is 15 ppm. ACHD Article XXI §2104.10 limits No. 2 oil sulfur content to 0.05%. The sulfur content of the ULSD fuel to be used in the fire water pump engine (15 ppm or 0.0015%) will comply with both standards.

5.7.5.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are methods of controlling SO_2 emissions from combustion sources, such as the use of low sulfur fuels (i.e., ULSD), maintaining optimum combustion efficiency, and implementing appropriate maintenance procedures.

Scrubber/Flue Gas Desulfurization

A scrubber (or desulfurization unit) is a control technology used to abate SO_2 emissions. Scrubbers use chemical and mechanical processes to remove SO_2 from the gas. However, according to a search of recently permitted facilities and the RBLC database, there are currently no fire water pump engines that employ this technology. Therefore, scrubbers are not considered available for these sources and therefore are not considered further in this analysis.

5.7.5.2 Step 2 – Eliminate Technically Infeasible Options

Good combustion practices and low sulfur fuels are essential for the operation and life-span of the combustion sources and will be used with for the proposed fire water pump engine. Therefore, good combustion practices and low sulfur fuels are technically feasible for the proposed fire water pump engine.

5.7.5.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices and low sulfur fuels are the only remaining technically feasible technologies for controlling SO_2 emissions. Therefore, a ranking is not necessary to establish the top technology.

5.7.5.4 Step 4 – Evaluate Economic, Environmental and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices, including low sulfur fuels, will be implemented as part of the design and operation of the fire water pump engine. Therefore, economic, environmental, and/or energy impacts were not assessed in this BACT analysis.

5.7.5.5 Step 5 – Proposed BACT

A review was conducted of SO_2 BACT determinations for fire water pump engines, including a search of the RBLC database and a review of information concerning recently permitted facilities with fire water pump engines.

The search identified one facility with emission rates for SO_2 less than the proposed 0.93 g/hp-hr (Energy Answers Arecibo Puerto Rico Renewable Energy Project). AEC understands this facility has yet to be built, and therefore have yet to demonstrate their emissions limit in practice.

Several facilities (Greensville Power Station, St. Joseph Energy Center, LLC, Crescent City Power, Arsenal Hill Power Plant, Salem Harbor Station Redevelopment, Wildcat Point Generation Faculty, Forsyth Energy Plant, PSEG Fossil LLC Sewaren Generating Facility, Chouteau Power Plant, Catoctin Power LLC, Footprint Power Salem Harbor Development LP, CPV Valley Energy Center Wawayanda, NY) have a more stringent SO_2 emissions limit, ranging from 0.003 lb/hr – 0.61 lb/hr when compared to the 0.93 g/hp-hr (0.65 lb/hr) emissions limit proposed by AEC. However, none of the facilities are using control technologies, and therefore the differences in emissions limits can be attributed to different engine manufacturers, makes, and model years.

A complete list of facilities with emergency generators from the RBLC is included in Table D-E-7.

AEC proposes good combustion practices, proper maintenance, limited annual operating hours, and the exclusive use of ULSD with a sulfur content of 15 ppm to minimize emissions of SO_2 from the fire water pump engine, which represents the most stringent controls available for this equipment. The proposed SO_2 emission limit is 0.93 g/hp-hr, based on the assumption of 100 percent conversion of the sulfur in the fuel to SO_2.

5.7.6 BACT for H_2SO_4

Emissions of H_2SO_4 from the fire water pump engine results from oxidation of sulfur contained within the fuel. While there are no post-combustion control technologies available for H_2SO_4 emissions control from a fire water pump engine, a top-down BACT analysis for H_2SO_4 was performed for completeness purposes.

5.7.6.1 Step 1 – Identify Available Control Technologies

Good Combustion Practices

Good combustion practices are a method of controlling H_2SO_4 emissions from fire water pump engines. Good combustion practices include the use of low sulfur fuels (e.g., ULSD), as well as maintaining optimum combustion efficiency and implementing appropriate maintenance procedures. A review of the RBLC database and other recently permitted facilities indicates no other available H_2SO_4 control technologies for the fire water pump engine.

5.7.6.2 Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices and low sulfur fuels are necessary for the operation of the proposed fire water pump engine. Therefore, good combustion practices and low sulfur fuels are technically feasible control technologies for the fire water pump engine.

5.7.6.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Good combustion practices, including the use of low sulfur fuels, are a technically feasible control technology for H_2SO_4 for the fire water pump engine. Therefore, a ranking to establish the top control technology has not been considered.

5.7.6.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Good combustion practices and low sulfur fuels will be implemented as part of the operation of the fire water pump engine. Therefore, economic, environmental, and/or energy impacts were not assessed in this BACT analysis.

5.7.6.5 Step 5 – Proposed BACT

As mentioned in Section 5.6.5 the applicable diesel fuel sulfur content specified by 40 CFR Part 60 Subpart IIII is 15 ppm (i.e., 0.0015%). In addition, the diesel fuel sulfur content specified in ACHD Article XXI §2104.10 limits No. 2 oil sulfur content to 0.05%. The sulfur content of the ULSD to be used in the fire water pump engine will comply with both standards.

Several facilities (Greensville Power Station, Salem Harbor Station Redevelopment, Wildcat Point Generation Facility, CPV Valley Energy Center Wawayanda, NY, and Woodbridge Energy Center) have a more stringent H_2SO_4 emissions limit when compared to the 0.11 g/hp-hr emissions limit proposed by AEC. However, none of the facilities are using control technologies, and therefore the differences in emissions limits can be attributed to different engine manufacturers, makes, and model years.

A complete list of facilities with emergency generators from the RBLC is included in Table D-E-8.

AEC proposes to use good combustion practices and proposes to use exclusively ULSD to minimize emissions of H_2SO_4 from the fire water pump engine. These technologies represent the most stringent controls available for this equipment and will be used to achieve an H_2SO_4 emissions limit of 0.011 lb/MMBtu for the fire water pump engine. The proposed emissions limit is based on the sulfur content of the fuel, and the assumptions that there is a 100% conversion of the sulfur in the fuel to SO_2, 10% conversion the SO_2 to SO_3, and 100% conversion of the SO_3 to H_2SO_4.

5.7.7 **BACT for GHG**

GHG emissions from the fire water pump engine result from oxidation of fuel carbon. This evaluation does not identify and discuss each of the five individual steps of the top-down BACT process, as CCS was determined not to be cost effective for the Project (see Section 5.3.7).

A review was conducted of GHG BACT determinations for fire water pump engines, including a search of the RBLC database and a review of information concerning recently permitted facilities with fire water pump engines. The results of the search, which can be found in Appendix D Table D-E-9, confirmed that the proposed GHG emissions limits for the fire water pump engine are consistent with fire water pump engines at recently permitted facilities and entries in the RBLC.

The use of energy efficient design and work practices will be used to minimize GHG emissions. Emissions from the fire water pump engine will be included in an annual Facility-wide GHG limit calculated on a 12-month rolling average which can be found in Table 5-17.

5.8 CONTROL TECHNOLOGY ANALYSIS FOR CIRCUIT BREAKERS –GHG

Circuit breakers used in the combined cycle CT process commonly use SF_6 as a dielectric, a known GHG. This section includes the BACT determination for the circuit breakers for SF_6 and the associated GHG BACT discussion.

5.8.1 Step 1 – Identify Available Control Technologies

An available technology to limit fugitive emissions is the use of SF_6 leak detectors, which operate at a 0.5% (i.e., 5,000 ppm) leak detection level. The modern circuit breakers are a totally enclosed-pressure system, which also limit fugitive emissions. The SF_6 detection system can be enhanced by equipping the circuit breaker with a density alarm, which alerts the system-user when 10% of the SF_6 (by weight) has escaped. This technology proactively alerts the system-user of any potential leaks before a major portion of the SF_6 gas has escaped.

Another possible control technology is the use of a non-GHG as a substitute dielectric. The National Institute of Standards and Technology (NIST) has identified potential substitutes for SF_6 in Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure* SF_6.

5.8.2 Step 2 – Eliminate Technically Infeasible Options

SF_6 is still the best performing dielectric gas for high voltage circuit breakers, according the NIST Technical Note 1425. Therefore, using an alternate dielectric gas in the circuit breakers can be eliminated as a technically infeasible option.

5.8.3 Step 3 – Rank Remaining Control Technologies

The use of SF_6 technology with leak detection is the only remaining technically feasible technology for controlling SF_6 emissions. Therefore, a ranking is not necessary to establish the top technology.

5.8.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

Economic, environmental, and/or energy impacts were not addressed in this analysis because the use of alternative, non-GHG substance for SF_6 as the dielectric material in the breakers is not technically feasible.

5.8.5 Step 5 – Proposed BACT

AEC proposes the use of circuit breakers equipped with 0.5% leak detection as the BACT for GHG fugitive emissions. AEC will limit emissions to 96.6 tons of CO_2e per year. AEC conducted a review of the RBLC database and recently permitted facilities. The emissions proposed by AEC are similar with what has been recently permitted.

A complete list of facilities with circuit breakers from the RBLC is included in Table D-F-1.

The proposed circuit breakers will be designed to meet American National Standards Institute (ANSI) C37.013 standards for high voltage circuit breakers. Fugitive emissions from the circuit breakers will be calculated utilizing the methodology in 40 CFR Part 98 Subpart DD, Electrical Transmission and Distribution Equipment Use. The fugitive GHG emissions will be limited to the individual GHG limit of 96.6 tons CO_2e per year and included in the annual Facility-wide 12-month rolling GHG limit.

5.9 CONTROL TECHNOLOGY ANALYSIS FOR NATURAL GAS PIPING COMPONENTS –GHG

Pipes transporting natural gas have the potential to leak CH_4, a GHG, into the atmosphere. This section presents the BACT determination for the natural gas piping components fugitive emissions and presents the GHG BACT determination. Additionally, AEC will initiate intentional periodic purging of natural gas related to piping maintenance and turbine startups/shutdowns, as required for equipment integrity and safety. AEC will implement best management practices, including routine inspections/monitoring to minimize fugitive leaks from the piping components.

5.9.1 Step 1 – Identify Available Control Technologies

Instrument Leak Detection and Repair (LDAR) programs and auditory, visual, and olfactory (AVO) monitoring are two techniques that have successfully been used to reduce CH_4 fugitive emissions from natural gas piping. An alternative to using monitoring systems is to implement leakless piping technology. For period natural gas piping purges, the only available control option is to minimize these events to the extent that is practical.

5.9.2 Step 2 – Eliminate Technically Infeasible Options

Leakless valve technology is used when extremely toxic or hazardous materials have the potential to be emitted but natural gas is not considered highly toxic and will not be stored in the amount considered to be hazardous. Additionally, leakless valve technology has not been achieved in practice for natural gas piping components, because shutdown of gas transmission to the CT would be required for repair or replacement of the leakless valve technology. Therefore, leakless valve technology is not considered "available" for natural gas piping components and is not considered further for this analysis.

5.9.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

LDAR programs and LDAR programs that include use of remote sensing devices (e.g., infrared camera) have been determined by U.S. EPA to provide a repeatable method for assessing natural gas piping fugitive emissions.[77] Quarterly LDAR instrument monitoring with a leak detection threshold of 10,000 ppmv (TCEQ 28M LDAR Program) is generally assigned a control efficiency of 75% for valves, relief valves, and sampling connections, 75% for compressors, and 30% for flanges. Quarterly instrument monitoring with a leak detection threshold of 500 ppmv (TCEQ 28VHP LDAR Program) is generally assigned a control efficiency of 97% for valves, relief valves, and sampling connections, 85% for compressors, and 30% for flanges.

Because pipeline natural gas is odorized with very small quantities of mercaptan, AVO monitoring is an effective method for identifying and correcting leaks in natural gas piping. Periodic AVO walk-through inspections provide predicted control efficiencies of 97% control for valves, flanges,

[77] 73 FR 78199-78219, December 22, 2008.

relief valves, and sampling connections, and 95% for compressors.[78] Therefore, AVO is able to achieve equivalent control efficiencies compared to LDAR.

5.9.4 Step 4 – Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies

AVO will be implemented in the design and operation of the natural gas piping components. Because AVO is able to achieve equivalent control efficiencies compared to LDAR, there is no additional environmental benefit to implementing LDAR. Therefore, LDAR is not considered further.

5.9.5 Step 5 – Proposed BACT

To determine the appropriate proposed BACT limits, AEC conducted a review of the RBLC database and recently permitted facilities. The results from the RBLC search can be found in Table D-F-1. AEC proposes to use daily AVO inspection walk-throughs as BACT for natural gas piping components in natural gas service. For periodic natural gas piping purges, the standard industry work practice of periodic walk-through inspections and minimizing these events is the only practical means of minimizing emissions and is therefore considered to be BACT for the purging events.

Based on the AVO control efficiency, AEC is proposing that the AVO program for control of fugitive CH_4 (GHG) emissions is BACT. AEC proposes that a rolling 12-month GHG limit of 274.73 tpy as CO_2e for fugitive natural gas pipeline emissions and 794.82 tpy as CO_2e for periodic natural gas piping purges are the BACT emission limits. The fugitive GHG emissions will be included in the annual Facility-wide 12-month rolling GHG limit.

[78] Control Efficiencies for TCEQ Leak Detection and Repair Programs
www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/control_eff.pdf

5.10 LOWEST ACHIEVABLE EMISSION RATE ANALYSIS FOR STORAGE TANKS –VOC

AEC has evaluated the control of VOC emissions from the proposed diesel-fuel storage tanks to determine LAER. A review of the RBLC database and other relevant permits indicates that ULSD fuel storage tanks generally have no add-on control technologies. Results discovered one facility (Kenai Nitrogen Operations) with a lower VOC emissions limit, but it has yet to demonstrate that limit in practice. AEC will limit VOC emissions to 0.03 tons of VOC per 12-month rolling period.

A complete list of facilities with storage tanks from the RBLC is included in Table D-G-1.

5.11 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR ROADWAYS –PM, PM_{10}, AND $PM_{2.5}$

As mentioned in Section 3-8 fugitive PM, PM_{10}, and $PM_{2.5}$ emissions are expected to be negligible since all of the roadways at the plant will be paved surfaces. For completeness purposes, this section includes the BACT determination for controlling fugitive PM, PM_{10}, and $PM_{2.5}$ emissions from roadways.

Fugitive dust emissions associated with routine traffic over paved and unpaved roads within the Project boundary are a source of PM, PM_{10}, and $PM_{2.5}$ emissions. While these emissions are expected to be negligible, they are required to be addressed as part of the BACT determination. Therefore, AEC proposes to take reasonable precautions to minimize PM emissions from onsite roadways as BACT for PM, PM_{10}, and $PM_{2.5}$ (see Appendix H - Fugitive Dust Prevention and Control Plan).

6. AIR QUALITY MODELING EVALUATION

Invenergy is proposing to construct the AEC, a natural gas-fired, combined-cycle, electric generating station to be located in Elizabeth Township, Allegheny County, Pennsylvania. The Project triggers NSR and requires a PSD permit. The Project results in PTE emissions that exceed the PSD SERs for CO, PM_{10}, and NO_X, which have an associated NAAQS. Therefore, a PSD air quality modeling evaluation is required as part of this Application for CO, PM_{10}, and NO_2. AEC will be located in Allegheny County, which is classified as nonattainment for the 2015 annual $PM_{2.5}$ NAAQS. It should be noted that portions of Allegheny County, including the Liberty-Clairton Area (The City of Clairton and Boroughs of Glassport, Liberty, Lincoln, and Port View) are classified nonattainment with the 1997 24-hour $PM_{2.5}$ NAAQS. As a result, ACHD also has requested a $PM_{2.5}$ air quality modeling analysis for the 24-hour and annual $PM_{2.5}$ NAAQS, including an evaluation for $PM_{2.5}$ precursors, be completed since the project has the potential to impact the $PM_{2.5}$ nonattainment areas.

The Project's emissions of air toxics exceed the de minimis levels determined under ACHD's "Policy for Air Toxics Review of Installation Permit Applications" (Policy). An air toxics modeling analysis was performed to evaluate carcinogenic and non-carcinogenic health risks of the Project. The results of this analysis were compared to the cumulative Maximum Individual Carcinogenic Risk (MICR) of 1×10^{-5} and the Hazard Quotient (HQ) and Cumulative Hazard Index (HI) which are 1.0 and 2.0, respectively.

As part of the air quality modeling evaluation, AEC submitted an air quality modeling protocol to the ACHD on January 21, 2019, that was subsequently approved on February 12, 2019. The air quality modeling evaluation followed the procedures outlined in the protocol and is described in detail in the following subsections. Information concerning the air quality modeling emissions inventories, technical air quality modeling approach, Class I impacts, air quality modeling results, and Class II impacts are provided as outlined below.

- Section 6.1 – Emissions Inventory Summary
- Section 6.2 – Air Quality Modeling Approach and Technical Information

- Section 6.3 – Class I Analyses
- Section 6.4 – Presentation of Air Quality Modeling Results
- Section 6.5– Class II Impacts

The air quality modeling evaluation demonstrated that the Project impacts were below Class I PSD Significant Impact Levels (SILs) for NO_2, $PM_{2.5}$, and PM_{10} for all averaging periods, below Class II PSD SILs for CO, $PM_{2.5}$ and PM_{10} for all averaging periods, and below the Class II PSD SILs for the NO_2 annual averaging period. The air quality modeling evaluation also demonstrated that the Project will not cause or contribute to any violation of the 1-hour NO_2, NAAQS. In addition, the air toxics modeling evaluation demonstrated that modeled concentrations from Project emissions are below toxics risk thresholds for both carcinogenic and non-carcinogenic health effects. Lastly, the Federal Land Managers (FLMs) from the U.S Forest Service (USFS) and the National Park Service (NPS) both indicated that no negative impacts as a result of the Project were anticipated; and therefore, no Air Quality Related Values (AQRV) analysis was requested. The air quality modeling analysis was conducted using conservative modeling techniques that demonstrated that the proposed facility, operating under all modes and worst-case meteorological conditions, would not result in adverse air quality impacts for applicable PSD pollutants

6.1 EMISSIONS INVENTORY SUMMARY

This section of the Application discusses the various emission inventories and the physical stack characteristics that were considered as part of the PSD air quality modeling evaluation. In order to complete a PSD evaluation, an initial inventory of project-related emissions was developed. Pollutants with project-related emissions resulting in modeled concentrations that were greater than the PSD SILs required a NAAQS analysis with local source emissions included. In addition, an air toxics emissions inventory was developed in order to complete the ACHD risk assessment.

6.1.1 **Worst-Case Load Emissions Inventory**

A load analysis was performed for the turbines to identify the worst-case operational conditions. The load analysis for the turbines consisted of full and partial load (approximately 40-50%) operations. The loads were evaluated at five ambient conditions: 50-year minimum, winter, average, summer, and 50-year maximum. The partial load scenarios did not include duct firing because the DB are not typically operated when operating at partial loads. Only the 100% load level was evaluated with and without duct firing. Three startup conditions were also evaluated: hot, warm, and cold. Shutdowns were not included in the load analysis because the operating period and emissions rates for shutdown are lower and the exhaust gas volume rates and temperatures are not significantly different than for the hot, warm, or cold startup. A summary of the operational conditions that were evaluated are presented in Table 6-1. The worst-case operational conditions and the design load (100% load with duct firing at average ambient conditions) identified were evaluated fully for the subsequent emissions inventories described in the following sections.

6.1.2 Significant Impact Analysis Emissions Inventory

For the SIL analysis, Project-wide emissions from the Project sources were used to model concentrations for comparison with the SILs. In addition to the worst-case load conditions, the design conditions (i.e., the permitted annual emissions) were evaluated for the SIL analysis. A summary of worst-case (as determined by the load analysis) and the design emissions rates for CO, PM_{10}, $PM_{2.5}$, and NO_X from the Project are presented in Table 6-2. It should be noted that startup conditions were only evaluated for the one-hour (CO and NO_2) and eight-hour (CO) standards.

AEC did not include the emergency generator and fire water pump (i.e., intermittent emissions sources) in the 1-hour NO_2 air quality modeling evaluations because it is reasonably assumed that they will not contribute to the distribution of daily maximum 1-hour concentrations based on guidance contained in U.S. EPA's March 1, 2011 memorandum[79]. Specifically, the guidance identifies an intermittent emissions source as a source that operates a limited number of hours (less than 500 hours), operates on a random schedule that cannot be controlled (except for periodic

[79] U.S. EPA 2011 – "Additional Clarification Regarding Application of Appendix W Modeling" U.S. Environmental Protection Agency Office of Air Quality Planning and Standards, Air Quality Assessment Division, Research Triangle Park, NC, March 1, 2011.

readiness testing), and is not directly related to the production of a product. The emergency generator and fire water pump at the Facility will meet all three of these intermittent unit criteria and therefore are not expected to contribute to the distribution of daily maximum 1-hour concentrations. In addition, the emergency generator and fire water pump will utilize ULSD and will not operate during a combustion turbine startup for emergency or periodic readiness testing purposes.

For other short-term modeling (e.g., 1- and 8-hour CO, 24-hour PM_{10} and $PM_{2.5}$), the modeled emissions rates for the emergency generator and fire water pump were based on routine (30-minutes, once per week) operational testing scenario. In addition, annual average emissions rates were based on the assumption that annual non-emergency operation will be limited to less than 100 hours per consecutive 12-months for each engine.

6.1.3 Cumulative Analysis Emissions Inventory

NO_2 (1-hour) modeled emissions from the Project resulted in ambient air concentrations greater than the SILs as discussed in Section 6.4. Therefore, a cumulative NO_X emission inventory was developed to demonstrate compliance with the NAAQS. The one-hour NO_2 NAAQS was evaluated using the cold startup condition. The facility-wide emissions inventory used for the SIL modeling (Table 6-2) was also used to evaluate the one-hour NO_2.

6.1.4 Local Source Emissions Inventory

A cumulative NO_X emissions inventory was developed to demonstrate compliance with the 1-hour NO_2 NAAQS and includes an emissions inventory of local sources. Guidance contained in U.S. EPA's March 1, 2011 memorandum (U.S. EPA 2011) was followed. Per the guidance, local NO_X emissions sources that are within 10 km of the Project were included in the NO_X local source inventory. This guidance assumes that the region of significant concentration gradient of a local source is equivalent to 10 times the local source release height. The 10 km distance was developed based on stack heights less than or equal to 100 m. AEC reviewed local sources outside of the 10 km and identified one source with a stack height greater than 100 m. The Genon Energy Inc., Cheswick Station boiler has a stack height of 168.4 m and is located about 35 km away from the Project site. The summary of local sources that were included in the 1-hour NO_2 NAAQS evaluation is provided in Table 6-3. The stack characteristics and emissions rates were provided by ACHD.

6.1.5 **Air Toxics Emissions Inventory**

The Project exceeds the de minimis emissions rate levels for HAPs for "all other air toxics", as shown in Table 6-4, in accordance with the ACHD Air Quality Program Policy. Hence, an air toxics modeling analysis was required to be performed to evaluate the effects of the Project for carcinogenic and non-carcinogenic health risks.

For the air toxics analysis, emissions from the Project's emissions units were used to model concentrations for comparison to human health risk thresholds. To evaluate the human health risk on an annual averaging period, the annualized emissions rates were calculated by taking the total pounds per year (lb/yr) of emissions for each emissions unit and dividing the total emissions by the annual operating hours for the respective emissions unit.

Potential emissions from the CT with auxiliary-fired HRSG with DB, auxiliary boiler, and dew point heater were included in the air toxics modeling evaluation. Because the emergency generator and fire water pump engines are emergency units, and only permitted for 100 hours of operation per year for weekly testing, these units were not included as part of the air toxics modeling analysis. A summary of the annualized emissions rates from the Project is presented in Table 6-5. Only those air toxics with established risk thresholds as identified by the ACHD Policy are further summarized in Section 6.4.5 and included in the emissions inventory. As summarized in Table 6-4, annual mass emissions of mercury, Polycyclic Organic Matter (POM), and HAP metals are each less than the *de minimis* levels, in accordance with the ACHD's Policy and, therefore, are not expected to significantly affect public health. Therefore mercury, POM, and HAP metals have not been included in the air toxics modeling analysis.

6.1.6 Physical Stack Characteristics

A listing of the physical stack characteristics for the emissions units that will be included in the various air quality modeling analyses is provided in Table 6-6. Information related to the physical stack characteristics includes unit location, base elevation, release height, stack temperature, stack diameter, and stack exit velocity. Base elevations are determined from Project plot plan drawings.

6.2 AIR QUALITY MODELING APPROACH AND TECHNICAL INFORMATION

This section presents the technical approach that was used to demonstrate compliance with the NAAQS, PSD increments and air toxics. The air dispersion model selection is discussed as well as the options that were used in the model. Supporting information such as land use determinations, building downwash analyses, meteorological data, and terrain data, is also presented in this section. The guidance provided in 40 CFR Part 51 Appendix W[80] was used to conduct the air quality modeling analyses. Additional guidance provided by the ACHD was incorporated, as needed.

6.2.1 Air Dispersion Model Selection

The AERMOD (**AER**MIC **MOD**el) air dispersion model was used to predict ambient air concentrations from the AEC. AERMOD is a 40 CFR Part 51 Appendix W air dispersion model approved for regulatory modeling applications. The current regulatory version of AERMOD is 18081. AEC utilized U.S. EPA's version of AERMOD and did not use a proprietary version of AERMOD.

The AERMOD modeling system consists of two pre-processors and the dispersion model. AERMET (Version 18081) is the meteorological pre-processor component and AERMAP

[80] "Guideline on Air Quality Models" (U.S. EPA 2017).

(Version 18081) is the terrain pre-processor component. The AERMAP pre-processor characterizes the surrounding terrain and generates receptor elevations. The AERMET pre-processor is used to generate an hourly profile of the atmosphere and uses a pre-processor, AERSURFACE (Version 13016), to process land use data for determining micrometeorological variables that are inputs to AERMET.

The AERMOD air dispersion model has various user selectable options that must be considered. U.S. EPA has recommended that certain options be selected when performing air quality modeling studies for regulatory purposes. The following regulatory default options were used in the AERMOD air quality modeling study:

- Stack-Tip Downwash (default)
- Elevated Terrain Effects (default)
- Calms Processing (default)
- No Exponential Decay for Rural Mode (default)
- Missing Data Processing
- Ambient Ratio Method 2 (ARM2, default)

6.2.2 Land Use Analysis

A land use analysis for the area surrounding the AEC was prepared based on 2011 USGS National Land Cover Data (NLCD 2011) for the area. Following U.S. EPA guidance[81], the land use designations were based on the land use classification scheme developed by Auer[82]. The Auer land use classifications designate developed high intensity land use (NLCD2011 Category 24) and developed medium intensity land use (NLCD2011 Category 23) as urban land use while the remaining NLCD2011 categories are considered to be rural land use. If more than 50% of the land use within a 3-km radius of the AEC is rural, then a rural designation should be used in the air dispersion model.

[81] U.S. EPA 2005 – 40 CFR Part 51 Appendix W "Guideline on Air Quality Models (Revised)", May 2017.
[82] Auer 1978, Auer Jr., A.H., – "Correlation of Land Use and Cover with Meteorological Anomalies", Journal of Applied Meteorology, 17:636-643, 1978.

To perform the land use analysis, geographical information system (GIS) software was used to review the various land use types contained in the NLCD2011 electronic land use dataset. Based on the GIS summary, the land use within a 3-km radius of the AEC is rural. Review of the NLCD2011 land use within a 3-km radius indicates that at least 50% is categized as rural. Therefore, the urban option was not selected in the AERMOD air dispersion model. The 3-km radius land use summary for the area surrounding the AEC is shown in Figure 6-1.

6.2.3 **Receptor Grid**

The receptor grid for the AERMOD analysis covers a 20 km square area that is centered on the proposed AEC. Receptors were referenced to the UTM coordinate system, Zone 17 using NAD 1983 datum. Rectangular coordinates were used to identify each receptor location. The rectangular receptor grid will be centered on the AEC and will have the following grid spacing:

- 50 meters out to ± 2 km
- 100 meters out to ± 5 km
- 500 meters out to ± 10 km

In addition to the main rectangular coordinate receptor grid, fence line receptors were used in the air quality modeling analysis. The fence line represents the location of fencing on the AEC property, which will restrict access to the public and therefore is considered the ambient air boundary. The fence line receptors were spaced approximately every 10 m. Fence line receptor elevations are based on the proposed plot plan for the proposed AEC, where available. Otherwise, receptor elevations were developed by AERMAP as described in the next paragraph. A plot of the inner portion of the receptor grid is shown in Figure 6-2.

Terrain elevations were assigned to the receptors. The AERMAP terrain pre-processor (Version 18081) and USGS 1/3 arc-second National Elevation Dataset (NED) files was used to determine representative terrain elevations for all of the receptors. The horizontal resolution of the NED data is every 10 m.

6.2.4 Meteorological Data

The entire processed meteorological dataset was provided to AEC by ACHD in October 2015 and confirmed to be utilized for this project by ACHD in January 2019. The meteorological data that was used for the air quality modeling study consists of five years of local data collected from January 1, 2010 through December 31, 2014 at the Liberty meteorological station (Station ID 00064). The meteorological data were processed with a previous version of AERMET (15181), however, no updates to AERMET have been made that will significantly affect the modeled concentrations. The Liberty meteorological station is located at South Allegheny High School, 12 km north-northwest of the Project Site. Upper air and cloud cover data from Pittsburgh, Pennsylvania National Weather Service (NWS) station (Station ID 94823 and KPIT) were combined with the Liberty data to form a complete dataset. The Pittsburgh, Pennsylvania NWS station is located approximately 47 km from the Project Site.

6.2.5 Meteorological Data Representativeness

An evaluation of the topography and geography surrounding the Liberty meteorological station to the topography and geography surrounding the Project Site shows that the Liberty meteorological station is representative of the meteorological conditions at the Project Site. Both sites can be characterized as being located in generally rolling terrain surrounded by a mix of forest and farmland interspersed with single family residential properties. AEC compared the locations of the available meteorological data around the Project Site and determined that the Liberty meteorological station was the closest. The Liberty meteorological station is located only 12 km north-northwest of the Project Site. The next closest meteorological monitoring site is the KPIT NWS station which is located 47 km from the Project Site. Based on the geographical proximity of the Liberty meteorological station to the Project Site, and guidance from ACHD, the Liberty meteorological data is considered representative of meteorological conditions at the Project Site, and, therefore, was used in the air quality modeling analyses. A figure identifying the Project Site, meteorological station and the topography and geography between the two sites is provided in Figure 6-3.

6.2.6 **Good Engineering Practice Stack Height Analysis**

The stacks at the proposed AEC were analyzed for the potential influence of building downwash on emissions and resulting ambient concentrations. Guidance contained in the U.S. EPA "Guideline for Determination of Good Engineering Practice (GEP) guidance document[83] and the U.S. EPA Building Profile Input Program (BPIP) for PRIME (BPIPPRM, 04274) was followed. To perform the building downwash analysis, a facility plot plan showing the proposed AEC buildings, structures, and stacks was digitized using GIS software. Buildings with multiple tiers were digitized as a single building with multiple tiers rather than multiple buildings with a single tier. Using the approach that incorporates building tiers preserves the actual representation of the physical characteristic of the buildings. The results of the GIS digitization of the AEC facility are presented in Figure 6-4.

6.2.7 **Background Ambient Air Data**

Ambient background 1-hour NO_2 concentrations must be considered for the NAAQS demonstration. The ambient background concentration was added to the cumulative modeled concentration resulting from the Project and local sources. AEC followed guidance contained in U.S. EPA's March 1, 2011 memorandum[84] which outlines a "Tier 2" approach for including background ambient NO_2 concentrations. The "Tier 2" approach is also further justified in U.S. EPA's September 30, 2014 memorandum[85]. The "Tier 2" approach incorporates background concentrations by season and hour-of-day. Specifically, the 3rd highest monitored NO_2 concentration for each hour (1-24) from each day over one season from the last three years was calculated and the appropriate value was added to the modeled concentration. A summary of the

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[83] U.S. EPA 1985 – "Guideline for Determination of Good Engineering Practice (GEP) Stack Height (Technical Support Document for Stack Height Regulations) Revised" EPA-450:4-80-023R, June 1985.
[84] U.S. EPA 2011 – "Additional Clarification Regarding Application of Appendix W Modeling" U.S. Environmental Protection Agency Office of Air Quality Planning and Standards, Air Quality Assessment Division, Research Triangle Park, NC, March 1, 2011.
[85] U.S. EPA 2014 – "Clarification On the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard" U.S. Environmental Protection Agency Office of Air Quality Planning and Standards, Air Quality Assessment Division, Research Triangle Park, NC, September 30, 2014.

monitored NO_2 seasonal diurnal 3rd highest average concentrations during 2015 through 2017 from the Charleroi, PA monitor is presented in Table 6-7.

The ambient NO_2 measurements from the Charleroi, PA monitoring site are representative of the background concentrations at AEC for the NAAQS demonstration. The basis for this proposal follows. The Charleroi, PA NO_2 ambient monitor in the City of Charleroi is located about 12 km southwest of the proposed AEC in the City of Charleroi. The City of Charleroi is a more urban setting than the rural location of the proposed AEC. The location of the Charleroi, PA ambient monitor in an urban setting will result in higher background NO_2 concentrations due to the proximity of industrial and mobile sources of NO_2 emissions to the ambient monitor. Therefore, the use of the Charleroi, PA ambient NO_2 monitor is a representative and conservative approach for establishing background data for AEC.

6.2.8 Evaluation of O_3 and $PM_{2.5}$ Secondary Formation Precursor Emissions

The 2017 amendments to 40 CFR Part 51 Appendix W require an evaluation of the potential for O_3 formation based on the emissions rates of VOCs and NO_X, both of which are precursor pollutants for O_3. In addition, NO_X is a precursor pollutant for the formation of $PM_{2.5}$. The proposed project will be major for NO_X emissions; and therefore, a discussion of the potential for NO_X and VOC emissions to act as a precursor pollutant is included. Although emissions of SO_2 are neither major nor significant, SO_2 is a precursor pollutant for $PM_{2.5}$ and was included in the precursor analysis.

To evaluate the impact of precursor emissions rates on O_3 formation, 40 CFR Part 51 Appendix W discusses the option to use Modeled Emissions Rates for Precursors (MERPs). U.S. EPA released draft guidance, in December 2016[86], that details methods to use MERPs as a Tier 1

[86] U.S. EPA 2016 – "Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program". U.S. Environmental Protection Agency Office of Air Quality Planning and Standards, Air Quality Assessment Division, Research Triangle Park, NC, December 2016.

approach to demonstrate the potential for O_3 formation from precursor emissions. Section 7 of the draft guidance includes examples of a MERP Tier 1 demonstration that is based on the U.S. EPA modeling assessments of precursors from representative photochemical grid modeling. The modeling assessments cover several example PSD permit scenarios.

The projected VOC emissions from the proposed project are preliminarily calculated to be 93.40 tpy, which is above the NNSR threshold for being a major source. The projected NO_X emissions from the proposed project is preliminarily calculated to be 145.71 tpy, which is above the PSD and NNSR threshold for being a major source. From Table 7.1 of the U.S. EPA MERP guidance document, Eastern U.S. MERP values are 814 tpy for VOC and 109 tpy for NO_X. Using Equation 6-1, an assessment of NO_X and VOC precursor emissions was evaluated for ozone:

$$\frac{EMIS_{NOx}}{MERP_{NOx}} + \frac{EMIS_{VOC}}{MERP_{VOC}} < 1 (Equation\ 6-1)$$

$$\frac{145.71 \text{ tpy}}{109 \text{ tpy}} + \frac{93.40 \text{ tpy}}{814 \text{ tpy}} = 1.45 < 1$$

Since the sum of the ratios above is greater than one, a cumulative analysis for O_3 must be done for this project. Using Equation 6-2, the cumulative impacts from the project were evalauted:

$$Background\_ozone \quad + \left(\frac{EMIS_{NOx}}{MERP_{NOx}} + \frac{EMIS_{VOC}}{MERP_{VOC}}\right) \times SIL\_ozone \\ \leq NAAQS\_ozone\ (Equation\ 6-2)$$

Where background O_3 is the average of 3-years of the design value from a representative background ozone monitor. The closest monitor to the project is the Charleroi monitor (42-125-0005), which measured an average design value of 68.3 parts per billion (ppb) for the years 2015 through 2017. Using this background ozone value, plus the project increases in Equation 6-2 results in the following cumulative impact:

$$68.3\,ppb + \left(\frac{145.71\text{ tpy}}{109\text{ tpy}} + \frac{93.40\text{ tpy}}{814\text{ tpy}}\right) \times 1\,ppb\ = 69.8\,ppb \leq 70\,ppb$$

Therefore, cumulative air quality impacts of ozone precursor emissions from the proposed project are not expected to increase the critical air quality threshold for O_3, as the additive secondary impacts on 8-hour daily O_3 concentrations plus the design value from the closest O_3 monitor are calculated to be less than the 8-hour O_3 NAAQS of 70 ppb.

To evaluate the $PM_{2.5}$ SIL for secondary formation, the equation from the December 2016 draft MERP guidance was used. For 24-hour $PM_{2.5}$, the NO_X MERP is 2,467 tpy and the SO_2 MERP is 675 tpy. Using Equation 6-3, an assessment of NO_X and SO_2 precursor emissions was evaluated for $PM_{2.5}$:

$$\frac{EMIS\_PM2.5}{SER\_PM2.5} + \frac{EMIS_{NOx}}{MERP_{NOx}} + \frac{EMIS_{SO2}}{MERP_{SO2}} < 1\ (Equation\ 6-3)$$

$$\frac{90.66\text{ tpy}}{10\text{ tpy}} + \frac{145.71\text{ tpy}}{2{,}467\text{ tpy}} + \frac{24.43\text{ tpy}}{675\text{ tpy}} = 9.2 > 1$$

The 24-hour $PM_{2.5}$ evaluation for secondary formation is greater than 1, SIL modeling with AERMOD was required to further evaluate the SIL. To evaluate the $PM_{2.5}$ SIL, Equation 6-4 was used to further evaluate the modeled concentrations:

$$\frac{HMC_{PM_{2.5}}}{SIL_{PM_{2.5}}} + \frac{EMIS_{SO_2}}{MERP_{SO_2}} + \frac{EMIS_{NOx}}{MERP_{NOx}} < 1\ (Equation\ 6-4)$$

$$\left(\frac{0.99\ \mu g/m^3}{1.2\ \mu g/m^3} + \frac{145.71\text{ tpy}}{2{,}467\text{ tpy}} + \frac{24.43\text{ tpy}}{675\text{ tpy}}\right) \times 100 = 92.36 < 100$$

To evaluate the annual $PM_{2.5}$ SIL for secondary formation, the same Equation 6-3 was used. For annual $PM_{2.5}$, the NO_X MERP is 10,037 tpy, and the SO_2 MERP is 4,013 tpy. Using Equation 6-4, an assessment of NO_X and SO_2 precursor emissions was evaluated for annual $PM_{2.5}$:

$$\frac{91.02\ \text{tpy}}{10\ \text{tpy}} + \frac{145.71\ \text{tpy}}{10{,}037\ \text{tpy}} + \frac{24.43\ \text{tpy}}{4{,}013\ \text{tpy}} = 9.1 > 1$$

The annual $PM_{2.5}$ evaluation for secondary formation is greater than 1, SIL modeling with AERMOD was required to further evaluate the SIL. To evaluate the $PM_{2.5}$ SIL, Equation 6-4 was used to further evaluate the modeled concentrations:

$$\left(\frac{0.08\ \mu\text{g/m}^3}{0.2\ \mu\text{g/m}^3} + \frac{145.71\ \text{tpy}}{10{,}037\ \text{tpy}} + \frac{24.43\ \text{tpy}}{4{,}013\ \text{tpy}}\right) \times 100 = 43.90 < 100$$

The Class I $PM_{2.5}$ SILs was also evaluated for secondary formation of $PM_{2.5}$ from precursors using equation 6-4 a summarized below for comparison to the 24-hour and annual $PM_{2.5}$ Class I SIL:

$$\left(\frac{0.066\ \mu\text{g/m}^3}{0.27\ \mu\text{g/m}^3} + \frac{145.71\ \text{tpy}}{2{,}467\ \text{tpy}} + \frac{24.43\ \text{tpy}}{675\ \text{tpy}}\right) \times 100 = 34.09 < 100$$

$$\left(\frac{0.0071\ \mu\text{g/m}^3}{0.05\ \mu\text{g/m}^3} + \frac{145.71\ \text{tpy}}{2{,}467\ \text{tpy}} + \frac{24.43\ \text{tpy}}{675\ \text{tpy}}\right) \times 100 = 16.30 < 100$$

As summarized above the precursor emissions were adequately considered and no further analysis is required.

6.3 CLASS I ANALYSES

There are four Class I areas located within 300 km of the proposed AEC. Therefore, an analysis of Class I AQRV and Class I PSD increments is required. A figure showing the distance and direction to the Class I areas listed below is provided in Figure 6-5:

- Otter Creek Wilderness Area –137 km
- Dolly Sods Wilderness Area –137 km
- Shenandoah National Park –236 km

- James River Face Wilderness Area –295 km

The following subsections summarize how the Class I AQRVs and PSD increments will be evaluated.

6.3.1 Class I AQRV Analysis Summary

AEC utilized the "Q/d" approach to evaluate whether a full Class I AQRV evaluation was required for the proposed project. Using this approach, "Q" is equal to the annualized maximum 24-hour emissions rate of PM_{10}, SO_2, NO_X, and H_2SO_4 in tpy, and "d" is the distance from the facility to the Class I area in km (e.g., Otter Creek Wilderness Area – 137 km). The annualized 24-hour emission rates are utilized to assess impacts of visibility. A Q/d evaluation was completed utilizing annual project emissions in order to assess impacts of deposition which are evaluated on an annual basis. The resulting Q/d ratios were less than 10, as shown in Table 6-8. Since the Q/d ratio is less than the screening threshold of 10 which was set by the FLMs in the October 2010 FLM AQRV Workgroup (FLAG) document[87], no Class I AQRV evaluation is required as part of the Project air permitting. The USFS and NPS indicated that no negative impacts as a result of the Project were anticipated and therefore no AQRV analysis was requested.

6.3.2 Class I PSD SIL Analysis Summary

To evaluate the $PM_{2.5}$, PM_{10} and NO_2 Class I PSD increments, AEC conducted an air quality modeling screening analysis that utilized AERMOD to predict project-related concentrations at the Class I areas within 300 km for comparison to the Class I SILs. AEC used a receptor grid placed 50 km from the Project. The receptor grid consisted of a single circle of receptors (with a radius of 50 km), and spacing of 500 m between each receptor.

[87] U.S. Forest Service, National Park Service, and U.S. Fish and Wildlife Service. 2010. Federal Land Managers' Air Quality Related Values Work Group (FLAG): Phase I Report—revised (2010). Natural Resource Report NPS/NRPC/NRR—2010/232. National Park Service, Denver, Colorado.

6.4 PRESENTATION OF AIR QUALITY MODELING RESULTS

This section of the application summarizes the results from the air quality modeling analyses. The various analyses include the worst-case load, SIL, NAAQS, and air toxics analyses. The air quality modeling results demonstrate that the Project impacts are below Class I PSD SILs for PM_{10}, $PM_{2.5}$, and NO_2 for all averaging periods, below Class II PSD SILs for CO, PM_{10}, and $PM_{2.5}$ for all averaging periods, and below the Class II PSD SIL for the NO_2 annual averaging periods. The air quality modeling also demonstrates that the Project will not cause or contribute to any violation of a one-hour NO_2 NAAQS. In addition, the air toxics modeling evaluation demonstrated that modeled concentrations from Project emissions are below toxics risk thresholds for both carcinogenic and non-carcinogenic health effects. The air quality modeling analysis was conducted using conservative air quality modeling techniques that demonstrated that the Project, operating under all modes and worst-case meteorological conditions, will not result in any adverse air quality impacts for applicable PSD pollutants.

6.4.1 **Worst-Case Load Analysis**

A load analysis was performed to define the worst-case condition for the turbines. The load analysis was performed for each of the load conditions: full load with and without duct firing, partial loads (approximately 40-50%), and startup/shutdown. The specific stack parameters (i.e., exhaust gas temperature and velocity) for each case were input into the model. An emission rate of 1.0 gram per second (g/s) per CT was used so that the results could be easily scaled for each pollutant. A summary of the load analysis worst-case results for CO, PM_{10}, $PM_{2.5}$, and NO_2 for each case is presented in Appendix F. A summary of the operational cases that resulted in the highest predicted concentration for each pollutant and averaging period are presented in Table 6-9.

The purpose of the load analysis was to distill the 13 steady-state operating scenarios and three startup scenarios down to a subset of worst-case scenarios. The worst-case scenarios were then included in the subsequent Class I SIL and Class II SIL analyses to determine if NAAQS and PSD increment analyses were necessary. This load analysis ensures that the worst-case of all the 13 operating scenarios will demonstrate compliance with the applicable air quality standards.

In addition to the worst-case scenarios, there are design load scenarios that were developed by using the PTE emissions rates as summarized in Table 3-14. The PTE emissions represent the annual emissions, which were calculated by determining the emissions associated with each operating mode (i.e., gas operation without duct firing, gas operation with duct firing, and startup/shutdown) and the hours per year that each operating mode is projected to operate. These design load scenarios represent the compilation of pollutant, and pollutant averaging period.

The base load (i.e., steady-state, 100% load) with duct firing mode is the most common operating mode. Therefore, stack characteristics were selected that corresponded to the average temperature conditions at 100% load with duct firing. The design load scenarios are included in the subsequent Class I SIL and Class II SIL analyses. Consistent with the worst-case analyses, the auxiliary equipment was modeled at annualized emissions rates for the entire year with the design load for the CTs for the annual modeling.

6.4.2 Class I Significant Impact Analysis

A Class I SIL analysis was performed to demonstrate that Project related emissions resulted in predicted concentrations below the Class I PM_{10}, $PM_{2.5}$, and NO_2 SILs. The worst-case operating condition and the design load were modeled for each pollutant and respective averaging period. Based on the five years of meteorological data, the Project related emissions resulted in predicted concentrations that were less than the Class I SILs for PM_{10}, $PM_{2.5}$, and NO_2 for each respective averaging period for both the worst-case load and the design load. The results from the Class I SIL analysis are provided in Table 6-10. Because Project related emissions resulted in modeled concentrations less than the Class I SILs, no Class I PSD increment modeling analysis is required.

6.4.3 **Class II Significant Impact Analysis**

A Class II SIL analysis was performed to determine if Project related emissions resulted in predicted concentrations above the Class II CO, PM_{10}, $PM_{2.5}$, and NO_2 SILs. In order to justify the use of the SILs to preclude the need for NAAQS and PSD increment analyses, a “headroom” test was conducted using ambient monitoring data to ensure that NO_2 (annual), CO (1-hr), CO (8-hr), $PM_{2.5}$ (24-hr), $PM_{2.5}$ (annual), and PM_{10} (24-hr) modeled concentrations are below the SILs, thus will not contribute to an exceedance of the NAAQS. The ambient NO_2 data is from the Charleroi, PA monitor, the ambient CO data is from the Pittsburgh, PA monitor, and the $PM_{2.5}$/PM_{10} data is from the Clairton, PA monitor. A summary of the 2015 to 2017 ambient monitoring data for NO_2 (annual), CO (1-hr), CO (8-hr), $PM_{2.5}$ (24-hr), $PM_{2.5}$ (annual), and PM_{10} (24-hr) ambient monitoring data is provided in Table 6-11. As shown in Table 6-11, modeled concentrations that are below the respective SIL will not cause an increase in ambient concentrations that has the potential to exceed the respective NAAQS. Therefore, the use of the SILs is appropriate for justifying that no NO_2 (annual), CO (1-hr), CO (8-hr), $PM_{2.5}$ (24-hr), $PM_{2.5}$ (annual), nor PM_{10} (24-hr) multi-source air quality modeling analyses will be required for these pollutants and averaging periods.

The worst-case operating load and the design load were modeled for each pollutant and respective averaging period. The results from the Class II SIL analysis are provided Table 6-12. Since Project related emissions resulted in modeled concentrations less than the Class II SILs for all pollutants and averaging periods except 1-hour NO_2, no NAAQS or Class II PSD increment modeling analysis is required. However, because Project related emissions resulted in modeled concentrations greater than the 1-hour NO_2 Class II SIL, a 1-hour NO_2 NAAQS modeling demonstration was conducted.

6.4.4 **National Ambient Air Quality Standards Analysis**

Because the Project related concentrations due to Project related emissions were above the 1-hour NO_2 Class II SILs, it was necessary to conduct a NAAQS air quality modeling analysis. For the 1-hour NO_2 NAAQS analysis, local sources within 10 km were included in the NO_2 NAAQS analysis. In addition, representative background concentrations were added to modeled concentrations. The results of the 1-hour NO_2 NAAQS analyses are shown in Table 6-13. The 5-year average of 98th percentile of the daily maximum 1-hour concentrations from the five years of meteorological data for the worst-case load and the design load are summarized. The 1-hour modeled NO_2 concentrations exceeded the NAAQS in all scenarios. However, a significant contribution analysis using maximum contribution files (.MDC or MAXDCOUNT keyword) revealed that all of the modeled 98th percentile of daily maximum 1-hour concentrations that exceeded the NAAQS were caused by the local sources. During the modeled 1-hour NO_2 exceedances, the modeled contribution from the AEC-only sources was under the one 1-hour NO_2 Class II SIL threshold (7.5 $\mu g/m^3$). The significant contribution analysis is consistent with USEPA guidance[88]. The significant contribution analysis demonstrates that the contribution of NO_2 concentrations due to AEC-only sources does not *cause or contribute* to violations of the 1-hour NO_2 NAAQS for the worst-case load or design load scenarios.

It should be noted that background concentrations were combined utilizing the "Tier 2" methodology as described in Section 6.2.7. Utilizing the "Tier 2" methodology is a conservative approach for combining background concentrations with modeled concentrations and most likely results in the double counting of NO_2 concentrations resulting from NO_2 concentrations from the local sources.

6.4.5 **Evaluation of Air Toxics Modeling Analysis**

AEC conducted the air toxics analysis in accordance with ACHD's Policy. The objective of the air toxics modeling evaluation was to demonstrate that the air toxics emissions from the Project will not pose a public health risk. The air toxics modeling assessment and results are presented in the following subsections.

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[88] USEPA Memorandum, dated March 1, 2011, from Tyler Fox, "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO2 National Ambient Air Quality Standard."

6.4.5.1 Toxicity Assessment

To evaluate the potential health risk from the Project due to air toxics emissions, the published carcinogenic and non-carcinogenic risk factors for the air toxics were used. Unit risk factors (URFs) are the dose-response values used to evaluate potential carcinogens. An inhalation URF is an upper-bound excess lifetime carcinogenic risk (expressed in cubic meters per microgram [m^3/µg]) estimated to result from continuous inhalation exposure to an air toxic at a concentration of 1 microgram per cubic meter (µg/m^3) in air.

Non-carcinogenic effects are evaluated by reference concentrations (RfCs) for inhalation exposure. The RfC is the continuous inhalation exposure concentration of a substance that is likely to be without an appreciable risk of adverse health effects to the human population over a lifetime. For non-carcinogenic effects, it is assumed that there exists an exposure level below which no adverse health effects will be observed. Below this "threshold" level, exposure to a substance can be tolerated without adverse effects. The potential for non-carcinogenic health effects resulting from inhalation exposure to substances is assessed by comparing an exposure concentration in air to an RfC. The RfC is expressed in units of milligrams per cubic meter (mg/m^3).

To compile the URF and RfC values, the U.S. EPA Integrated Risk Information System (IRIS) database was consulted along with other regulatory sources for health affects related to air toxics. The following hierarchy of sources were used to determine these values, in accordance with guidance in ACHD's Policy:

- Tier 1 – U.S. EPA's IRIS. In the development of IRIS toxicity values, U.S. EPA undertakes rigorous scientific process and includes toxicity values that are subject to both internal and external peer review by scientific experts and agency consensus review.
- Tier 2 – U.S. EPA's Provisional Peer Reviewed Toxicity Values (PPRTVs). The Office of Research and Development/National Center for Environmental Assessment/Superfund Health Risk Technical Support Center (STSC) develops PPRTVs on a chemical specific basis when requested by the U.S. EPA Superfund program.
- Tier 3 – Other toxicity values. Tier 3 includes additional U.S. EPA and non-U.S. EPA sources of toxicity information. Sources of Tier 3 values include: California Environmental Protection Agency (Cal EPA) Reference Exposure Levels (RELs), Agency

for Toxic Substances and Disease Registry (ATSDR) Minimal Risk levels (MRLs), and Health Effects Assessment Summary Tables (HEAST) toxicity values.

The list of URFs, RfCs, and their references, is shown in Table 6-14. The RfC values were converted to μg/m^3 for unit consistency.

The carcinogenic and non-carcinogenic risks were determined following the approach in the ACHD's Policy. Individual AERMOD runs were completed for each of the five years of meteorological data (2010-2014), utilizing the Project-wide emissions rates for each air toxic and physical stack characteristics outlined in Section 6.1.6. The maximum annual concentration from the five model runs was then used to estimate the carcinogenic and non-carcinogenic risks of the Project.

6.4.5.1.1 Carcinogenic Risk Characterization

For the carcinogenic risk assessment, the Maximum Individual Carcinogenic Risk (MICR) was calculated for each carcinogenic air toxic. The MICR was calculated using the following equation:

Equation 6-5

$$MICR = Modeled\ Maximum\ Annual\ Concentration * URF$$

where "MICR" equals the Maximum Individual Carcinogenic Risk, "Modeled Maximum Annual Concentration" equals the air toxic-specific concentration modeled by AERMOD, and "URF" equals the air toxic-specific unit risk factor.

The cumulative MICR for the mixture of carcinogens is equal to the sum of the MICRs for each individual substance. According to ACHD's Policy, if the cumulative MICR for the Project is less than 1 x 10^{-5} at or beyond the Project Site's public exposure boundary, no further assessment for carcinogenic effects is required. If the cumulative MICR for the Project is greater than 1 x 10^{-5} at or beyond the Project Site's public exposure boundary, a cumulative analysis is required, which takes into account actual emissions from nearby existing sources. As summarized in Section

6.4.5.2 the cumulative MICR for the Project is less than 1 x 10^{-5} and, therefore, no cumulative analysis is required.

6.4.5.1.2 Non-Carcinogenic Risk Characterization

For non-carcinogenic risks, the Hazard Quotient (HQ) was calculated for each non-carcinogenic air toxic. The HQ was calculated using the following equation:

Equation 6-6

$$HQ = \frac{Modeled\ Maximum\ Annual\ Concentration}{RfC}$$

where "HQ" equals the Hazard Quotient, "Modeled Maximum Annual Concentration" equals the air toxic-specific concentration modeled by AERMOD, and "RfC" equals the air toxic-specific reference concentration.

The cumulative Hazard Index (HI) for non-carcinogens is equal to the sum of the HQs for substances that affect the same target organ or organ system. All the toxics evaluated were conservatively summed regardless of organ system. According to ACHD's Policy, if the HQ of each non-carcinogen is less than 1.0 and the HI for the Project is less than 2.0 at or beyond the Project's property line, no further assessment of non-carcinogenic effects is required. If the HQ of any non-carcinogen is greater than 1.0 or the HI for the Project is greater than 2.0 at or beyond the public exposure boundary, a cumulative analysis is required, which takes into account actual emissions from nearby existing sources. As summarized in Section 6.4.5.3 the HQ and HI are less than 1.0 and 2.0, respectively, and therefore no cumulative analysis is required.

6.4.5.2 Carcinogenic Risks

The results of the carcinogenic risk assessment are shown in Table 6-15. The cumulative MICR is 5.37 x 10^{-7}, which is less than the carcinogenic risk threshold of 1.0 x 10^{-5}. Therefore, no further risk assessment is required.

6.4.5.3 Non-Carcinogenic Risks

The results of the non-carcinogenic risk assessment are also shown in Table 6-15. The HI is 0.02, which is less than the non-carcinogenic risk threshold of 2.0. Also, there are no individual HQs that are greater than 1.0. Therefore, no further risk assessment is required.

6.4.5.4 Summary of Air Toxics Modeling Evaluation

AEC conducted an air toxics modeling analysis, in accordance with guidance in the ACHD Air Toxics Policy, to evaluate the carcinogenic and non-carcinogenic health risks associated with the Project. The assessment used published toxic emissions factors, conservative stack parameters, conservative air quality modeling techniques, and published toxicity values. The cumulative MICR values were calculated for the carcinogenic risk, and the HQ and HI values were calculated for the non-carcinogenic risk. The MICR, HQs, and HI were below the risk thresholds determined by ACHD; therefore, no further assessment is required. The analysis demonstrates that air toxics emissions due to the Project will not cause adverse carcinogenic or non-carcinogenic health effects.

6.5 CLASS II ADDITIONAL IMPACTS ANALYSIS

A discussion of the impacts of the Project on the Class II area surrounding the facility is provided in this subsection. As part of this discussion, visibility will be evaluated and the potential growth in air quality related impacts resulting from the Project will be estimated. Additionally, acidification of rainfall and impacts on soil and vegetation will be qualitatively addressed.

6.5.1 **Class II Visibility Modeling**

As part of the Class II impacts analysis, AEC completed a visibility analysis to assess the potential for a visible plume to impact non-Class I areas. Specifically, AEC evaluated the potential for the Project to cause a visible plume at Allegheny Islands State Park, which is approximately 34 km to the northwest of the Project. The Allegheny Islands State Park was selected as it is the closest state-operated recreational site to the Project.

To conduct the Class II visibility analysis, AEC used the U.S. EPA VISCREEN model and the guidance contained in the "Workbook for Plume Visual Impact Screening and Analysis", U.S. EPA report number EPA-450/4-88-015. As part of this analysis, AEC used the annual Project related emissions of PM, NO_X, and H_2SO_4 (default assumptions were used for conversions to NO_2). In addition, AEC incorporated a default O_3 concentration level of 0.04 ppb, default wind speed of 1.0 m/s, and default atmospheric stability category of “F.” A visual range of 25 km was used. The selected visual range is representative of the Allegheny County area. A summary of the VISCREEN output file is contained on the DVD with the Project air quality modeling files in Appendix F. The calculated plume perceptibility and contrast parameters for SKY background were determined to be below the U.S. EPA default criteria for a visibility screening analysis for an observer located inside and outside the Class II sensitive area. Therefore, the results demonstrate that the Project plume will not impact visibility at the identified potentially sensitive areas nearest to the Project and no further visibility assessment is necessary.

6.5.2 **Potential Growth**

In general, it is anticipated that the Project will have insignificant impacts on secondary source growth in the area of Allegheny County with respect to air quality related impacts. While several hundred construction jobs will be created during the construction phase of the Project, these jobs will be temporary. According to 2017 U.S. Census Bureau estimates, the population of Allegheny County is about 1.2 million persons thus, many of the construction workers will be employed from the locally available trades people. Adequate short-term housing and other services are available in the immediate vicinity of the Project site to accommodate any temporary additional work force required.

Once the Project becomes operational, approximately 16 full-time staff will be employed. This number of employees, even if all were to be new residents in the immediate area, would have little impact on the need for housing and related commercial services. According to the U.S. Census Bureau there are about 596,000 housing units in Allegheny County. These figures prove that adequate existing housing, transportation and other services are present in the local area to absorb the small number of full-time staff required to operate the proposed facility.

No significant impact is expected on roadways used for construction or operation of the Project due to the existing nature of the transportation system in the vicinity of the Project Site. Smithdale Road, which is the main road adjacent to the Project Site, is a major thoroughfare used by existing commercial and industrial companies located in the vicinity of the Project site. That road is well constructed to accommodate the traffic related to the construction and operation of the Project.

For these reasons, no significant air quality impacts due to secondary source growth are anticipated during the construction or operational phase of the Project.

6.5.3 Adverse Impacts on Vegetation and Soils

Vegetation can be impacted from the emission of excessive amounts of common atmospheric pollutants such as SO_2, NO_X, CO, CO_2, hydrogen fluoride, O_3, hydrocarbons, particulates and metals (Malhotra and Khan, 1984). In general, however the main atmospheric pollutants that affect vegetation are nitrogen-based, sulfur-based, and O_3, with O_3 causing more damage to plants than all other air pollutants combined[89]. The sensitivity of vegetation to atmospheric pollution varies greatly with such factors as plant species and variety, climatic and seasonal conditions, soil composition, the concentration and duration of exposure, and the nature of combinations of pollutants[90,91].

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[89] Burkey, Kent O. – "Effects of Ozone on Apoplast/Cytoplasm Partitioning of Ascorbic Acid in Snap Bean" U.S. Department of Agriculture, Agricultural Research Service and Department of Crop Science and Botany, North Carolina State University, Raleigh, NC, April 29, 1999.
[90] Treshow, Michael – "Air Pollution and Plant Life" Environmental Monographs and Symposia, 1984.
[91] Whitmore, M.E. – "Relationships between dose of SO_2 and NO_2 mixtures and growth of Poa prantensis" New Phytol 99, 1985.

A summary of research on air pollution effects on vegetation divides air pollution injuries to plants into three general categories: acute, chronic, and subtle[90]. Acute injury is caused by exposure to a high concentration of a substance resulting in rapid visible death of some tissue. Chronic injury is caused by long-term exposure to low pollutant levels which gradually disrupts physiological processes and retards growth or yield[92]. The subtle effects of air pollution on vegetation are difficult to quantify since the threshold concentrations and exposure times that may cause subtle damage are difficult to define. AEC has addressed the potential for damage to vegetation from the NO_X and particulates as the PSD significant pollutants in the following paragraph.

Potential damage to vegetation in the area surrounding the Project from NO_X is unlikely. In general, acute damage to vegetation is not likely to occur at ambient air concentration levels below the 1-hour NO_2 NAAQS, although some reduction in growth might occur at continuous NO_2 concentration levels as low as 200 – 500 $\mu g/m^3$ [91,93]. These values are significantly above the 1-hour NO_2 NAAQS (188 $\mu g/m^3$). In view of the small increase in ambient concentration levels anticipated as a result of the Project, adverse effects on vegetation from NO_X emissions are not expected to occur.

Particulate matter is not likely to cause adverse effects on vegetation. Investigation of particulate effects on plants has generally shown no damage, although some interference with respiration and photosynthesis might occur if heavy crusts of dust accumulate on moist plant tissue[94]. This level of accumulation is more likely to be associated with heavy agricultural or construction activities than with highly controlled industrial particulate emissions. Furthermore, natural weather conditions tend to remove dust and particulates from plant surfaces before heavy accumulations

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[92] Slinn, W.G. et al. – "Some Aspects of the Transfer of Atmospheric Trace Constituents Past the Air-Sea Interface" Atmosphere and Environment, 1978.

[93] Joosting, P.E., and ten Houten, J.G. – "Biological Effects of Air Pollution", 1972.

[94] Prajapati, Santosh Kumar – "Ecological effect of airborne particulate matter on plants" Department of Botany, Guru Ghasidas Vishwavidyalaya, Bitlaspur (C.G.), India, IAEES, March 10, 2012.

can build up. Consequently, no adverse effects on vegetation are expected to result from $PM/PM_{10}/PM_{2.5}$ emissions due to the Project.

Additionally, the emissions of non-criteria pollutants will not adversely impact vegetation due to similar reasoning regarding possible adverse soil impacts. The profile of non-criteria pollutants and magnitude of emissions are not expected to cause detrimental impacts to vegetation as pollutants that potentially could cause acidic deposition (e.g., H_2SO_4 emissions) are minimal and none of the fuels proposed to be utilized by AEC contain mercury in any appreciable amounts. It should also be noted that emissions of volatile HAPs are included in the assessment of VOC emissions from the facility. As noted in Section 6.4.5, VOC emissions are not anticipated to contribute to a significant increase in O_3 levels at the Project Site and thus will not adversely affect vegetation.

Allegheny County is part of the Allegheny Mountain Plateau Section. This section of Pennsylvania topography is characterized by wide and undulating valleys with rounded broad ridges running in northeast/southwest directions. The soil characteristics within Allegheny County and the Project Site were determined using United States Department of Agriculture (USDA) soil survey reports and data[95]. Specifically, soil information for an approximately 10 km square area centered on the Project Site was reviewed. The review indicated that silt and loam composition was the primary soil type with a stony silt composition also occurring frequently. The surface pH of both main soil types range between 4.5 and 5.5.

The emissions from the Project are well controlled and will be unlikely to result in adverse effects to the local soil. Since natural gas is the primary fuel, there will be minimal sulfur emissions that could result in acidic sulfur deposition. Similarly, NO_X emissions are controlled via the use of SCR and thus minimum nitric deposition would be expected. Emissions of other non-criteria

[95] U.S. Department of Agriculture, Soil Conservation Service – "Soil Survey of Allegheny County, Pennsylvania", 1981.

pollutants would not be expected to cause adverse effects on local soil due to the very low levels at which the pollutants are proposed to be emitted.

6.5.4 Environmental Justice Areas

A review of Environmental Justice Areas (EJA) within the significant impact area as determined by the 1-hour NO_2 SIL analysis was conducted. An EJA is defined as an area having a poverty rate of 20% or greater or a non-white population of 30% or greater as determined by 2015 Pennsylvania Census Block Group data. There are two census tracks in Westmoreland County located within three km of the proposed AEC that are classified as EJAs. Figure 6-66 shows a map identifying the EJAs surrounding the proposed AEC.

ACHD does not have an Environmental Justice (EJ) policy. As part of the permitting of the proposed Project, AEC will initiate expanded outreach and public participation in cooperation with PADEP and ACHD.

Once the Facility is operating, AEC will have minimal effect on the surrounding air quality, water resources, and land. As noted, emissions from the Project will be limited by using BACT and LAER, the use of natural gas, and good operating practices to reduce emissions. In addition, air quality modeling has demonstrated that de-minimis ambient air concentrations will result from Facility emissions, thus the existing air quality will not be adversely affected. There will be minor amounts of solid waste generated by operations at the Facility, and the wastes that are generated will be managed in accordance with PADEP waste regulations. There will be no waste discharges to the surrounding land. Finally, the Facility will not be a major source of HAPs nor will the facility trigger the Chemical Accident Prevention Provisions at 40 CFR Part 68, which includes the RMP provisions. Therefore, AEC does not believe that the proposed Project will adversely affect the health and welfare of the surrounding communities regardless of the income level, ethnic origin, or race of the individuals within the communities.

SECTION 6 TABLES AND FIGURES

Table 6-1
Summary of Evaluated Turbine Operating Conditions
Invenergy LLC - Allegheny Energy Center

Case Number	Ambient Temperature (^oF)	Turbine Load	Duct Firing
15	-26	100%	Operating
17		100%	Off
18		50%	Off
4	9	100%	Operating
5		100%	Off
1	53	100%	Operating
2		100%	Off
11	87.5	100%	Operating
13		100%	Off
14		37%	Off
21	101.8	100%	Operating
23		100%	Off
24		41%	Off
Cold Start	N/A	N/A	N/A
Warm Start	N/A	N/A	N/A
Hot Start	N/A	N/A	N/A
Shutdown	N/A	N/A	N/A

Table 6-2
Facility-Wide Emissions Inventory[(a)]
Invenergy LLC - Allegheny Energy Center

Emissions Unit	Pollutant	Averaging Period	Case	AERMOD ID	Emissions Rate (lb/hr)
Auxiliary Boiler[(b)]	PM_{10}	24-hr	N/A	AUXBOIL	0.1318
		Annual			0.06
	$PM_{2.5}$	24-hr			0.1090
		Annual			0.05
	NO_X	1-hr			0.98
		Annual			0.45
	CO	1-hr			3.62
		8-hr			3.62
Dew Point Heaters	PM_{10}	24-hr	N/A	DEWPT	0.00
		Annual			0.00
	$PM_{2.5}$	24-hr			0.00
		Annual			0.00
	NO_X	1-hr			0.03
		Annual			0.03
	CO	1-hr			0.11
		8-hr			0.11
Emergency Generators[(c)]	PM_{10}	24-hr	N/A	EGEN	0.024
		Annual			0.013
	$PM_{2.5}$	24-hr			0.02
		Annual			0.013
	NO_X	Annual			0.35
	CO	1-hr			17.60
		8-hr			17.60
Fire Water Pump[(c)]	PM_{10}	24-hr	N/A	FP	0.002
		Annual			0.001
	$PM_{2.5}$	24-hr			0.002
		Annual			0.001
	NO_X	Annual			0.02
	CO	1-hr			1.62
		8-hr			1.62
Combustion Turbine	PM_{10}	24-hr	Worst-Case[(c)]	S37U	13.60
		Annual		S37U	13.60
	$PM_{2.5}$	24-hr		S37U	13.60
		Annual		S37U	13.60
	NO_X	1-hr		CS	252.58
		Annual		W100FB	30.90
	CO	1-hr		CS	901.57
		8-hr		CS	901.57
	PM_{10}	24-hr and Annual	Design[(d)]	CTPTE	20.63
	$PM_{2.5}$	24-hr and Annual		CTPTE	20.63
	NO_X	1-hr and Annual		CTPTE	32.42
	CO	1-hr and 8-hr		CTPTE	36.92

[(a)] Facility-wide emissions inventory is used for both the Significant Impact Analysis modeling and the cumulative NAAQS modeling.

[(b)] The annual emissions rates are calculated by annualizing the emissions based on the number of operating hours per year.

[(c)] 24-hour averaging period emission rates were divided by 48 to account for 30-minutes of testing in a 24-hour period. In addition annual emissions were divided by 8,760 hours in order to annualize 100 hours of annual operation.

[(c)] The AERMOD ID for the CT represent the cases determined to be worst-case from the load analysis.

[(d)] The design scenarios are calculated using the potential to emit emissions.

Table 6-3

Local Source NO_X Emissions Inventory and Stack Parameters

Invenergy LLC - Allegheny Energy Center

Site Name/Stack	AERMOD ID	NO_X (tpy)	UTM X Coordinate (m)	UTM Y Coordinate (m)	Elevation (m)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)	Distance to AEC (km)
BASIC CARBIDE CORP/BUENA VISTA	CARB1	0.11	602,380.01	4,457,460.32	282.00	4.27	293.15	0.001	0.30	4.07
CLAIRTON SLAG INC/WEST ELIZABETH PAVING MATL PLT	SLAG1	8.10	593,695.99	4,458,273.31	230.00	8.84	295.22	23.84	0.40	10.02
KELLY RUN SANI/MSW LDFL	KELLY1	15.63	594,649.01	4,456,398.28	355.00	10.67	1,160.93	0.80	2.03	8.35
GENON POWER MIDWEST LP/ELRAMA POWER PLT	ELRAMA	561.12	592,059.01	4,456,413.28	229.00	119.48	324.80	15.07	7.92	10.81
Eastman Chemical Resins, Inc. - BOILERS 1-2	ECRB12	0.94	593,092.57	4,457,578.88	225.00	14.33	616.48	8.70	0.70	10.25
Eastman Chemical Resins, Inc. - BOILERS 3-4	ECRB34	1.60	593,092.57	4,457,578.88	225.00	18.29	616.48	17.40	0.70	10.25
Eastman Chemical Resins, Inc. - NO. 5 TRANE BOILER	ECRB5	12.72	593,100.94	4,457,590.09	225.00	22.25	560.93	15.90	0.91	10.24
Eastman Chemical Resins, Inc. - HOT OIL HEATER, NG	ECRHOH	1.83	593,092.57	4,457,578.88	225.00	6.10	616.48	7.45	0.34	10.25
Eastman Chemical Resins, Inc. - LTC Unit #1	ECRLTC1	1.02	593,092.57	4,457,578.88	225.00	6.10	810.78	16.76	0.30	10.25
Eastman Chemical Resins, Inc. - LTC Unit #2	ECRLTC2	1.11	593,092.57	4,457,578.88	225.00	6.10	616.33	23.77	0.30	10.25
Eastman Chemical Resins, Inc. - Thermal Oxidizer	ECRTO	11.42	593,092.57	4,457,578.88	225.00	15.24	293.15	0.12	0.24	10.25
Eastman Chemical Resins, Inc. - Misc. NG	ECRMNG	0.93	593,092.57	4,457,578.88	225.00	3.05	293.15	0.01	0.03	10.25
Eastman Chemical Resins, Inc. - Hydro Unit Heater, NG	ECRHNG	1.79	593,092.57	4,457,578.88	225.00	6.10	293.15	34.74	0.06	10.25
Eastman Chemical Resins, Inc. - Vehicle Exhaust	ECRVE	3.62	593,092.57	4,457,578.88	225.00	6.10	293.15	0.01	0.03	10.25
Peoples Natural Gas Co/WALL Comp. Station	PNGCS	42.50	595,188.70	4,453,823.64	318.00	6.10	293.15	0.01	0.24	7.27
US STEEL IRVIN Boiler #1	IRBLR1	19.9725	593,149.00	4,465,476.00	287.00	19.50	635.38	10.23	1.10	15.25
US STEEL IRVIN Boiler #2	IRBLR2	23.4439	593,171.00	4,465,165.00	287.00	21.94	537.05	8.00	1.28	14.99
US STEEL IRVIN Boilers #3-4	IRBLR3	12.6494	593,419.00	4,465,596.00	287.00	22.86	644.26	9.70	1.42	15.18
US STEEL IRVIN 80" Mill Reheat Furnace 1	IR80IN1	130.2518	593,177.00	4,465,871.00	287.00	20.00	710.38	29.43	1.98	15.55
US STEEL IRVIN 80" Mill Reheat Furnace 2	IR80IN2	129.5317	593,178.00	4,465,884.00	287.00	20.00	710.38	29.43	1.98	15.56
US STEEL IRVIN 80" Mill Reheat Furnace 3	IR80IN3	121.4517	593,179.00	4,465,896.00	287.00	20.00	710.38	29.43	1.98	15.57
US STEEL IRVIN 80" Mill Reheat Furnace 4	IR80IN4	132.4266	593,180.00	4,465,909.00	287.00	20.00	710.38	29.43	1.98	15.58
US STEEL IRVIN 80" Mill Reheat Furnace 5	IR80IN5	120.0247	593,181.00	4,465,923.00	287.00	20.00	710.38	29.43	1.98	15.59
US STEEL IRVIN 80" Mill Reheat Waste Stack 6	IR80INW	13.2347	593,243.00	4,465,922.00	287.00	28.34	710.38	29.43	1.82	15.55
US STEEL IRVIN #1 Galv Line Preheat	IRGALV1	4.091	593,352.00	4,465,406.00	287.00	25.30	944.26	9.48	1.42	15.07
US STEEL IRVIN #2 Galv Line Preheat	IRGALV2	4.8934	593,350.00	4,465,386.00	287.00	26.82	944.26	2.66	1.37	15.05
US STEEL IRVIN HPH Annealing Furnaces (seg a)	IRHPH_a	3.3062714	593,328.56	4,465,585.48	287.00	21.33	527.60	10.00	0.76	15.23
US STEEL IRVIN HPH Annealing Furnaces (seg b)	IRHPH_b	3.3062714	593,325.15	4,465,553.51	287.00	21.33	527.60	10.00	0.76	15.20
US STEEL IRVIN HPH Annealing Furnaces (seg c)	IRHPH_c	3.3062714	593,321.76	4,465,521.64	287.00	21.33	527.60	10.00	0.76	15.18
US STEEL IRVIN HPH Annealing Furnaces (seg d)	IRHPH_d	3.3062714	593,318.44	4,465,489.75	287.00	21.33	527.60	10.00	0.76	15.16
US STEEL IRVIN HPH Annealing Furnaces (seg e)	IRHPH_e	3.3062714	593,315.27	4,465,457.80	287.00	21.33	527.60	10.00	0.76	15.13
US STEEL IRVIN HPH Annealing Furnaces (seg f)	IRHPH_f	3.3062714	593,311.57	4,465,425.87	287.00	21.33	527.60	10.00	0.76	15.11
US STEEL IRVIN HPH Annealing Furnaces (seg g)	IRHPH_g	3.3062714	593,308.19	4,465,393.98	287.00	21.33	527.60	10.00	0.76	15.09
US STEEL IRVIN Open Coil Annealing	IROCA	13.7173	593,335.00	4,465,243.00	287.00	21.33	310.94	10.52	2.96	14.95
US STEEL IRVIN Continuous Annealing	IRCONTA	6.0931	593,341.00	4,464,903.00	287.00	36.57	513.72	10.52	1.07	14.68
US STEEL IRVIN Peach Tree Flare A&B	IRPTF	4.4282	592,868.00	4,464,808.00	333.00	18.28	1,273.00	20.00	0.63	14.90
US STEEL IRVIN COG Flares 1-3	IRCOGF	2.7033	593,237.00	4,464,601.00	287.00	8.99	1,273.00	20.00	0.63	14.51
US STEEL CLAIRTON Quench Tower 1	CLQNCH1	0.69	595,964.00	4,461,731.00	231.00	30.48	358.49	3.54	6.80	10.56
US STEEL CLAIRTON Quench Tower 5	CLQNCH5	0.93	595,472.00	4,462,078.00	231.00	30.48	358.49	3.54	7.10	11.14
US STEEL CLAIRTON Quench Tower 7	CLQNCH7	1.05	595,430.00	4,462,047.00	231.00	37.18	362.77	2.99	8.81	11.14
US STEEL CLAIRTON Quench Tower B	CLQNCHB	0.87	595,460.00	4,462,374.00	231.00	41.15	368.55	4.30	9.51	11.38
US STEEL CLAIRTON Quench Tower C	CLQNCHC	0.00	595,622.00	4,462,186.00	231.00	50.00	378.00	3.66	12.67	11.13
US STEEL CLAIRTON Quench Tower 5A	CLQNCH5A	0.00	595,223.00	4,462,366.00	231.00	50.00	378.00	3.66	12.67	11.52
US STEEL CLAIRTON Quench Tower 7A	CLQNCH7A	0.00	595,188.00	4,462,316.00	231.00	50.00	378.00	3.66	12.67	11.50
US STEEL CLAIRTON PEC Baghouse 1-3 (seg a)	CLPEC1a	5.65	595,865.75	4,461,872.18	231.00	24.99	324.83	8.84	1.22	10.74
US STEEL CLAIRTON PEC Baghouse 1-3 (seg b)	CLPEC1b	5.65	595,861.10	4,461,877.19	231.00	24.99	324.83	8.84	1.22	10.74
US STEEL CLAIRTON PEC Baghouse 1-3 (seg c)	CLPEC1c	5.65	595,856.39	4,461,882.39	231.00	24.99	324.83	8.84	1.22	10.75
US STEEL CLAIRTON PEC Baghouse 13-15 (seg a)	CLPEC13a	7.34	595,324.70	4,462,210.47	231.00	24.99	324.83	16.95	0.91	11.34
US STEEL CLAIRTON PEC Baghouse 13-15 (seg b)	CLPEC13b	7.34	595,320.28	4,462,215.54	231.00	24.99	324.83	16.95	0.91	11.34
US STEEL CLAIRTON PEC Baghouse 13-15 (seg c)	CLPEC13c	7.34	595,315.94	4,462,220.42	231.00	24.99	324.83	16.95	0.91	11.35
US STEEL CLAIRTON PEC Baghouse 19-20 (seg a)	CLPEC19a	8.28	595,319.97	4,462,206.37	231.00	24.99	304.83	15.60	0.91	11.34
US STEEL CLAIRTON PEC Baghouse 19-20 (seg b)	CLPEC19b	8.28	595,315.54	4,462,211.35	231.00	24.99	304.83	15.60	0.91	11.34
US STEEL CLAIRTON PEC Baghouse 19-20 (seg c)	CLPEC19c	8.28	595,311.02	4,462,216.53	231.00	24.99	304.83	15.60	0.91	11.35
US STEEL CLAIRTON PEC Baghouse B (seg a)	CLPECBa	3.68	595,439.48	4,462,426.08	231.00	15.54	324.83	13.78	1.22	11.43
US STEEL CLAIRTON PEC Baghouse B (seg b)	CLPECBb	3.68	595,430.87	4,462,433.71	231.00	15.54	324.83	13.78	1.22	11.45
US STEEL CLAIRTON PEC Baghouse B (seg c)	CLPECBc	3.68	595,420.91	4,462,441.34	231.00	15.54	324.83	13.78	1.22	11.46
US STEEL CLAIRTON PEC Baghouse C	CLPECC	0.00	595,678.00	4,462,007.00	231.00	30.00	328.20	15.10	2.49	10.96

Table 6-3

Local Source NO_X Emissions Inventory and Stack Parameters

Invenergy LLC - Allegheny Energy Center

Site Name/Stack	AERMOD ID	NO_X (tpy)	UTM X Coordinate (m)	UTM Y Coordinate (m)	Elevation (m)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)	Distance to AEC (km)
US STEEL CLAIRTON Battery 1 Underfiring	CLCOMB1	192.13	595,871.00	4,461,845.00	231.00	68.58	526.49	7.59	2.44	10.71
US STEEL CLAIRTON Battery 2 Underfiring	CLCOMB2	181.10	595,866.00	4,461,852.00	231.00	68.58	534.27	7.71	2.44	10.72
US STEEL CLAIRTON Battery 3 Underfiring	CLCOMB3	198.62	595,742.00	4,461,989.00	231.00	68.58	539.27	7.38	2.44	10.90
US STEEL CLAIRTON Battery 13 Underfiring	CLCOMB13	129.75	595,389.00	4,462,164.00	231.00	68.58	535.38	4.48	3.05	11.26
US STEEL CLAIRTON Battery 14 Underfiring	CLCOMB14	121.81	595,380.00	4,462,174.00	231.00	68.58	536.49	4.30	3.05	11.27
US STEEL CLAIRTON Battery 15 Underfiring	CLCOMB15	152.02	595,253.00	4,462,318.00	231.00	68.58	541.49	4.48	3.05	11.46
US STEEL CLAIRTON Battery 19 Underfiring	CLCOMB19	339.26	595,273.00	4,462,117.00	231.00	76.20	519.27	3.72	4.72	11.30
US STEEL CLAIRTON Battery 20 Underfiring	CLCOMB20	546.23	595,258.00	4,462,134.00	231.00	76.20	542.05	4.27	4.72	11.32
US STEEL CLAIRTON B Battery Underfiring	CLCOMBB	371.80	595,477.00	4,462,406.00	231.00	96.01	515.38	5.06	4.95	11.40
US STEEL CLAIRTON C Battery Underfiring	CLCOMBC	0.00	595,768.00	4,462,126.00	231.00	98.14	503.20	5.81	3.66	11.00
US STEEL CLAIRTON Boiler 1	CLBLR1	455.29	595,004.00	4,462,714.00	231.00	57.91	457.60	29.56	2.67	11.93
US STEEL CLAIRTON Boiler 2	CLBLR2	170.92	594,989.00	4,462,717.00	231.00	57.91	437.05	21.94	2.13	11.94
US STEEL CLAIRTON Boiler R1	CLBLRR1	6.09	594,892.00	4,462,604.00	231.00	50.29	524.27	7.47	2.59	11.91
US STEEL CLAIRTON Boiler R2	CLBLRR2	4.21	594,892.00	4,462,604.00	231.00	50.29	524.27	7.47	2.59	11.91
US STEEL CLAIRTON Boiler T1	CLBLRT1	14.32	594,845.00	4,462,563.00	231.00	26.52	544.27	9.05	1.46	11.91
US STEEL CLAIRTON Boiler T2	CLBLRT2	10.85	594,837.00	4,462,569.00	231.00	26.52	543.16	9.05	1.46	11.92
US STEEL CLAIRTON SCOT Incinerator	CLSCOT	0.90	595,575.00	4,462,036.00	231.00	45.72	638.16	17.43	1.17	11.04
US STEEL CLAIRTON Misc. Flaring	CLFLARE	19.81	595,580.00	4,462,050.00	231.00	8.26	1,273.00	20.00	0.63	11.05
US STEEL CLAIRTON Batteries 1-3 Soaking	CLB1S1	0.03141	595,736.56	4,461,971.88	231.00	10.50	1,366.49	6.10	0.46	10.89
US STEEL CLAIRTON Batteries 1-3 Soaking	CLB1S2	0.03141	595,753.45	4,461,952.91	231.00	10.50	1,366.49	6.10	0.46	10.87
US STEEL CLAIRTON Batteries 1-3 Soaking	CLB1S3	0.03141	595,770.35	4,461,933.93	231.00	10.50	1,366.49	6.10	0.46	10.84
US STEEL CLAIRTON Batteries 1-3 Soaking	CLB1S4	0.03141	595,787.25	4,461,914.95	231.00	10.50	1,366.49	6.10	0.46	10.82
US STEEL CLAIRTON Batteries 1-3 Soaking	CLB1S5	0.03141	595,804.15	4,461,895.97	231.00	10.50	1,366.49	6.10	0.46	10.79
US STEEL CLAIRTON Batteries 1-3 Soaking	CLB1S6	0.03141	595,821.05	4,461,876.99	231.00	10.50	1,366.49	6.10	0.46	10.77
US STEEL CLAIRTON Batteries 1-3 Soaking	CLB1S7	0.03141	595,837.95	4,461,858.01	231.00	10.50	1,366.49	6.10	0.46	10.74
US STEEL CLAIRTON Batteries 1-3 Soaking	CLB1S8	0.03141	595,854.85	4,461,839.03	231.00	10.50	1,366.49	6.10	0.46	10.72
US STEEL CLAIRTON Batteries 1-3 Soaking	CLB1S9	0.03141	595,871.75	4,461,820.05	231.00	10.50	1,366.49	6.10	0.46	10.69
US STEEL CLAIRTON Batteries 1-3 Soaking	CLB1S10	0.03141	595,888.65	4,461,801.07	231.00	10.50	1,366.49	6.10	0.46	10.66
US STEEL CLAIRTON Batteries 1-3 Soaking	CLB1S11	0.03141	595,905.55	4,461,782.09	231.00	10.50	1,366.49	6.10	0.46	10.64
US STEEL CLAIRTON Batteries 1-3 Soaking	CLB1S12	0.03141	595,922.44	4,461,763.12	231.00	10.50	1,366.49	6.10	0.46	10.61
US STEEL CLAIRTON Batteries 13-15 Soaking	CLB13S1	0.0458	595,275.68	4,462,318.79	231.00	10.80	1,366.49	6.10	0.46	11.45
US STEEL CLAIRTON Batteries 13-15 Soaking	CLB13S2	0.0458	595,293.14	4,462,299.33	231.00	10.80	1,366.49	6.10	0.46	11.43
US STEEL CLAIRTON Batteries 13-15 Soaking	CLB13S3	0.0458	595,310.61	4,462,279.87	231.00	10.80	1,366.49	6.10	0.46	11.40
US STEEL CLAIRTON Batteries 13-15 Soaking	CLB13S4	0.0458	595,328.07	4,462,260.42	231.00	10.80	1,366.49	6.10	0.46	11.37
US STEEL CLAIRTON Batteries 13-15 Soaking	CLB13S5	0.0458	595,345.54	4,462,240.96	231.00	10.80	1,366.49	6.10	0.46	11.35
US STEEL CLAIRTON Batteries 13-15 Soaking	CLB13S6	0.0458	595,363.00	4,462,221.50	231.00	10.80	1,366.49	6.10	0.46	11.32
US STEEL CLAIRTON Batteries 13-15 Soaking	CLB13S7	0.0458	595,380.46	4,462,202.04	231.00	10.80	1,366.49	6.10	0.46	11.29
US STEEL CLAIRTON Batteries 13-15 Soaking	CLB13S8	0.0458	595,397.93	4,462,182.58	231.00	10.80	1,366.49	6.10	0.46	11.27
US STEEL CLAIRTON Batteries 13-15 Soaking	CLB13S9	0.0458	595,415.39	4,462,163.13	231.00	10.80	1,366.49	6.10	0.46	11.24
US STEEL CLAIRTON Batteries 13-15 Soaking	CLB13S10	0.0458	595,432.86	4,462,143.67	231.00	10.80	1,366.49	6.10	0.46	11.22
US STEEL CLAIRTON Batteries 13-15 Soaking	CLB13S11	0.0458	595,450.32	4,462,124.21	231.00	10.80	1,366.49	6.10	0.46	11.19
US STEEL CLAIRTON Batteries 19-20 Soaking	CLB19S1	0.0569	595,232.65	4,462,250.77	231.00	12.50	1,366.49	6.10	0.46	11.43
US STEEL CLAIRTON Batteries 19-20 Soaking	CLB19S2	0.0569	595,250.06	4,462,231.15	231.00	12.50	1,366.49	6.10	0.46	11.40
US STEEL CLAIRTON Batteries 19-20 Soaking	CLB19S3	0.0569	595,267.47	4,462,211.54	231.00	12.50	1,366.49	6.10	0.46	11.37
US STEEL CLAIRTON Batteries 19-20 Soaking	CLB19S4	0.0569	595,284.88	4,462,191.92	231.00	12.50	1,366.49	6.10	0.46	11.35
US STEEL CLAIRTON Batteries 19-20 Soaking	CLB19S5	0.0569	595,302.29	4,462,172.31	231.00	12.50	1,366.49	6.10	0.46	11.32
US STEEL CLAIRTON Batteries 19-20 Soaking	CLB19S6	0.0569	595,319.71	4,462,152.69	231.00	12.50	1,366.49	6.10	0.46	11.29
US STEEL CLAIRTON Batteries 19-20 Soaking	CLB19S7	0.0569	595,337.12	4,462,133.08	231.00	12.50	1,366.49	6.10	0.46	11.27
US STEEL CLAIRTON Batteries 19-20 Soaking	CLB19S8	0.0569	595,354.53	4,462,113.46	231.00	12.50	1,366.49	6.10	0.46	11.24
US STEEL CLAIRTON Batteries 19-20 Soaking	CLB19S9	0.0569	595,371.94	4,462,093.85	231.00	12.50	1,366.49	6.10	0.46	11.22
US STEEL CLAIRTON Batteries 19-20 Soaking	CLB19S10	0.0569	595,389.35	4,462,074.23	231.00	12.50	1,366.49	6.10	0.46	11.19
US STEEL CLAIRTON B Battery Soaking	CLBBS1	0.0947	595,519.57	4,462,333.89	231.00	17.10	1,366.49	6.10	0.46	11.31
US STEEL CLAIRTON B Battery Soaking	CLBBS2	0.0947	595,536.28	4,462,315.20	231.00	17.10	1,366.49	6.10	0.46	11.29
US STEEL CLAIRTON B Battery Soaking	CLBBS3	0.0947	595,553.00	4,462,296.50	231.00	17.10	1,366.49	6.10	0.46	11.26
US STEEL CLAIRTON B Battery Soaking	CLBBS4	0.0947	595,569.72	4,462,277.80	231.00	17.10	1,366.49	6.10	0.46	11.24
US STEEL CLAIRTON B Battery Soaking	CLBBS5	0.0947	595,586.43	4,462,259.11	231.00	17.10	1,366.49	6.10	0.46	11.21
US STEEL CLAIRTON C Battery Soaking	CLBCS1	0.00	595,661.57	4,462,174.90	231.00	17.10	1,366.49	6.10	0.46	11.10

Table 6-3

Local Source NO_X Emissions Inventory and Stack Parameters

Invenergy LLC - Allegheny Energy Center

Site Name/Stack	AERMOD ID	NO_X (tpy)	UTM X Coordinate (m)	UTM Y Coordinate (m)	Elevation (m)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)	Distance to AEC (km)
US STEEL CLAIRTON C Battery Soaking	CLBCS2	0.00	595,676.94	4,462,157.74	231.00	17.10	1,366.49	6.10	0.46	11.08
US STEEL CLAIRTON C Battery Soaking	CLBCS3	0.00	595,692.31	4,462,140.58	231.00	17.10	1,366.49	6.10	0.46	11.05
US STEEL CLAIRTON C Battery Soaking	CLBCS4	0.00	595,707.69	4,462,123.42	231.00	17.10	1,366.49	6.10	0.46	11.03
US STEEL CLAIRTON C Battery Soaking	CLBCS5	0.00	595,723.06	4,462,106.26	231.00	17.10	1,366.49	6.10	0.46	11.01
US STEEL CLAIRTON C Battery Soaking	CLBCS6	0.00	595,738.43	4,462,089.10	231.00	17.10	1,366.49	6.10	0.46	10.98
US STEEL CLAIRTON Batteries 1-3 PEC Fugitives (pushing + car)	CLB1P1	0.03141	595,747.54	4,461,978.87	231.00	8.50	1,033.16	3.05	1.59	10.89
US STEEL CLAIRTON Batteries 1-3 PEC Fugitives (pushing + car)	CLB1P2	0.03141	595,764.17	4,461,960.08	231.00	8.50	1,033.16	3.05	1.59	10.87
US STEEL CLAIRTON Batteries 1-3 PEC Fugitives (pushing + car)	CLB1P3	0.03141	595,780.80	4,461,941.28	231.00	8.50	1,033.16	3.05	1.59	10.84
US STEEL CLAIRTON Batteries 1-3 PEC Fugitives (pushing + car)	CLB1P4	0.03141	595,797.43	4,461,922.49	231.00	8.50	1,033.16	3.05	1.59	10.82
US STEEL CLAIRTON Batteries 1-3 PEC Fugitives (pushing + car)	CLB1P5	0.03141	595,814.06	4,461,903.69	231.00	8.50	1,033.16	3.05	1.59	10.79
US STEEL CLAIRTON Batteries 1-3 PEC Fugitives (pushing + car)	CLB1P6	0.03141	595,830.69	4,461,884.90	231.00	8.50	1,033.16	3.05	1.59	10.77
US STEEL CLAIRTON Batteries 1-3 PEC Fugitives (pushing + car)	CLB1P7	0.03141	595,847.31	4,461,866.10	231.00	8.50	1,033.16	3.05	1.59	10.74
US STEEL CLAIRTON Batteries 1-3 PEC Fugitives (pushing + car)	CLB1P8	0.03141	595,863.94	4,461,847.31	231.00	8.50	1,033.16	3.05	1.59	10.72
US STEEL CLAIRTON Batteries 1-3 PEC Fugitives (pushing + car)	CLB1P9	0.03141	595,880.57	4,461,828.51	231.00	8.50	1,033.16	3.05	1.59	10.69
US STEEL CLAIRTON Batteries 1-3 PEC Fugitives (pushing + car)	CLB1P10	0.03141	595,897.20	4,461,809.72	231.00	8.50	1,033.16	3.05	1.59	10.67
US STEEL CLAIRTON Batteries 1-3 PEC Fugitives (pushing + car)	CLB1P11	0.03141	595,913.83	4,461,790.92	231.00	8.50	1,033.16	3.05	1.59	10.64
US STEEL CLAIRTON Batteries 1-3 PEC Fugitives (pushing + car)	CLB1P12	0.03141	595,930.46	4,461,772.13	231.00	8.50	1,033.16	3.05	1.59	10.62
US STEEL CLAIRTON Batteries 13-15 PEC Fugitives (pushing + car)	CLB13P1	0.0458	595,266.65	4,462,308.76	231.00	8.80	1,033.16	3.05	1.59	11.45
US STEEL CLAIRTON Batteries 13-15 PEC Fugitives (pushing + car)	CLB13P2	0.0458	595,283.82	4,462,289.41	231.00	8.80	1,033.16	3.05	1.59	11.42
US STEEL CLAIRTON Batteries 13-15 PEC Fugitives (pushing + car)	CLB13P3	0.0458	595,300.99	4,462,270.06	231.00	8.80	1,033.16	3.05	1.59	11.40
US STEEL CLAIRTON Batteries 13-15 PEC Fugitives (pushing + car)	CLB13P4	0.0458	595,318.16	4,462,250.71	231.00	8.80	1,033.16	3.05	1.59	11.37
US STEEL CLAIRTON Batteries 13-15 PEC Fugitives (pushing + car)	CLB13P5	0.0458	595,335.33	4,462,231.35	231.00	8.80	1,033.16	3.05	1.59	11.35
US STEEL CLAIRTON Batteries 13-15 PEC Fugitives (pushing + car)	CLB13P6	0.0458	595,352.50	4,462,212.00	231.00	8.80	1,033.16	3.05	1.59	11.32
US STEEL CLAIRTON Batteries 13-15 PEC Fugitives (pushing + car)	CLB13P7	0.0458	595,369.67	4,462,192.65	231.00	8.80	1,033.16	3.05	1.59	11.29
US STEEL CLAIRTON Batteries 13-15 PEC Fugitives (pushing + car)	CLB13P8	0.0458	595,386.84	4,462,173.29	231.00	8.80	1,033.16	3.05	1.59	11.27
US STEEL CLAIRTON Batteries 13-15 PEC Fugitives (pushing + car)	CLB13P9	0.0458	595,404.01	4,462,153.94	231.00	8.80	1,033.16	3.05	1.59	11.24
US STEEL CLAIRTON Batteries 13-15 PEC Fugitives (pushing + car)	CLB13P10	0.0458	595,421.18	4,462,134.59	231.00	8.80	1,033.16	3.05	1.59	11.22
US STEEL CLAIRTON Batteries 13-15 PEC Fugitives (pushing + car)	CLB13P11	0.0458	595,438.35	4,462,115.24	231.00	8.80	1,033.16	3.05	1.59	11.19
US STEEL CLAIRTON Batteries 19-20 PEC Fugitives (pushing + car)	CLB19P1	0.0569	595,243.66	4,462,257.78	231.00	10.50	1,033.16	3.05	1.59	11.42
US STEEL CLAIRTON Batteries 19-20 PEC Fugitives (pushing + car)	CLB19P2	0.0569	595,260.96	4,462,238.38	231.00	10.50	1,033.16	3.05	1.59	11.40
US STEEL CLAIRTON Batteries 19-20 PEC Fugitives (pushing + car)	CLB19P3	0.0569	595,278.26	4,462,218.99	231.00	10.50	1,033.16	3.05	1.59	11.37
US STEEL CLAIRTON Batteries 19-20 PEC Fugitives (pushing + car)	CLB19P4	0.0569	595,295.55	4,462,199.59	231.00	10.50	1,033.16	3.05	1.59	11.35
US STEEL CLAIRTON Batteries 19-20 PEC Fugitives (pushing + car)	CLB19P5	0.0569	595,312.85	4,462,180.20	231.00	10.50	1,033.16	3.05	1.59	11.32
US STEEL CLAIRTON Batteries 19-20 PEC Fugitives (pushing + car)	CLB19P6	0.0569	595,330.15	4,462,160.80	231.00	10.50	1,033.16	3.05	1.59	11.29
US STEEL CLAIRTON Batteries 19-20 PEC Fugitives (pushing + car)	CLB19P7	0.0569	595,347.45	4,462,141.41	231.00	10.50	1,033.16	3.05	1.59	11.27
US STEEL CLAIRTON Batteries 19-20 PEC Fugitives (pushing + car)	CLB19P8	0.0569	595,364.74	4,462,122.01	231.00	10.50	1,033.16	3.05	1.59	11.24
US STEEL CLAIRTON Batteries 19-20 PEC Fugitives (pushing + car)	CLB19P9	0.0569	595,382.04	4,462,102.62	231.00	10.50	1,033.16	3.05	1.59	11.22
US STEEL CLAIRTON Batteries 19-20 PEC Fugitives (pushing + car)	CLB19P10	0.0569	595,399.34	4,462,083.22	231.00	10.50	1,033.16	3.05	1.59	11.19
US STEEL CLAIRTON B Battery PEC Fugitives (pushing)	CLBBP1	0.0947	595,506.60	4,462,322.92	231.00	15.10	1,033.16	3.05	1.95	11.31
US STEEL CLAIRTON B Battery PEC Fugitives (pushing)	CLBBP2	0.0947	595,523.30	4,462,304.46	231.00	15.10	1,033.16	3.05	1.95	11.29
US STEEL CLAIRTON B Battery PEC Fugitives (pushing)	CLBBP3	0.0947	595,540.00	4,462,286.00	231.00	15.10	1,033.16	3.05	1.95	11.26
US STEEL CLAIRTON B Battery PEC Fugitives (pushing)	CLBBP4	0.0947	595,556.70	4,462,267.54	231.00	15.10	1,033.16	3.05	1.95	11.24
US STEEL CLAIRTON B Battery PEC Fugitives (pushing)	CLBBP5	0.0947	595,573.40	4,462,249.08	231.00	15.10	1,033.16	3.05	1.95	11.21
US STEEL CLAIRTON C Battery PEC Fugitives (pushing + car)	CLBCP1	0.00	595,650.59	4,462,163.92	231.00	15.10	1,033.16	3.05	1.95	11.10
US STEEL CLAIRTON C Battery PEC Fugitives (pushing + car)	CLBCP2	0.00	595,665.55	4,462,147.35	231.00	15.10	1,033.16	3.05	1.95	11.08
US STEEL CLAIRTON C Battery PEC Fugitives (pushing + car)	CLBCP3	0.00	595,680.52	4,462,130.78	231.00	15.10	1,033.16	3.05	1.95	11.05
US STEEL CLAIRTON C Battery PEC Fugitives (pushing + car)	CLBCP4	0.00	595,695.48	4,462,114.22	231.00	15.10	1,033.16	3.05	1.95	11.03
US STEEL CLAIRTON C Battery PEC Fugitives (pushing + car)	CLBCP5	0.00	595,710.45	4,462,097.65	231.00	15.10	1,033.16	3.05	1.95	11.01
US STEEL CLAIRTON C Battery PEC Fugitives (pushing + car)	CLBCP6	0.00	595,725.41	4,462,081.08	231.00	15.10	1,033.16	3.05	1.95	10.99
NRG Cheswick Main Boiler (FGD stack)	CHESWICK	3,294.21	602,375.00	4,488,256.00	231.00	168.40	326.38	12.47	8.15	34.87

Table 6-4

Air Toxics De Minimis Levels vs. Project Emissions

Invenergy LLC - Allegheny Energy Center

Air Toxic	**ACHD *De Minimis* Level[a]**	**Project Emissions**	**Are Project Emissions ≥ ACHD *De Minimis* Level?[b]**
Polychlorobiphenols	20 lb/yr	Not Expected to be Emitted	-
Polycyclic Organic Matter (POM)	20 lb/yr	0.72 lb/yr	No
Mercury	20 lb/yr	0.96 lb/yr	No
Dioxins and Furans	0.02 lb/yr	Not Expected to be Emitted	-
HAP Metals	20 lb/yr	15.81 lb/yr	***No***
All Other Air Toxics	0.25 tpy	14.34 tpy	***Yes***

[a] De minimis levels are from the ACHD Air Quality Program “Policy for Air Toxics Review of Installation Permit Applications.”

[b] If Project emissions are greater than or equal to the ACHD de minimis levels for air toxics, an air toxics analysis is required.

Table 6-5
Facility-Wide Toxics Emissions Inventory
Invenergy LLC - Allegheny Energy Center

Emissions Unit Description								CT[a]	DB[a]	Auxilary Boiler	Dew Point Heater	Emergency Generator	Fire Water Pump
Case Number								12	2	N/A	N/A	N/A	N/A
Operating Time, hrs/yr								8,760	8,760	4,000	8,760	100	100
Fuel Type								Natural Gas	Natural Gas	Natural Gas	Natural Gas	ULSD	ULSD
Heat Input (HHV), Max. MMBtu/hr each unit								3,844	394	88.7	3.0	20.9	1.9
Number of Units								1	1	1	1	2	3
Air Toxic	Note	CAS Number	Emissions Factors for Natural Gas-Fired Turbines	Emissions Factors for Natural Gas Combustion	Emissions Factors for Large Diesel Engines	Emissions Factors for Small Diesel Engines	Emissions Factors for Trace Metals from Distillate Oil Combustion	Annual Emissions	Annual Emissions	Annual Emissions	Annual Emissions	Annual Emissions	Annual Emissions
			AP-42 Ch 3.1	AP-42 Ch 1.4	AP-42 Ch 3.4	AP-42 Ch. 3.3	AP-42 Ch 1.3						
			(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)
Polychlorobiphenols													
Not Expected to be Emitted													
Polycyclic Organic Matter (POM)													
2-Methylnaphthalene		91-57-6	-	2.29E-08	-	-	-	-	3.95E-05	4.05E-06	3.00E-07	-	-
3-Methylchloranthrene	(b)	56-49-5	-	1.71E-09	-	-	-	-	2.96E-06	3.04E-07	2.25E-08	-	-
7,12-Dimethylbenz(a)anthracene	(b)	57-97-6	-	1.52E-08	-	-	-	-	2.63E-05	2.70E-06	2.00E-07	-	-
Acenaphthene	(b)	83-32-9	-	1.71E-09	4.68E-06	1.42E-06	-	-	2.96E-06	3.04E-07	2.25E-08	2.96E-06	4.13E-07
Acenaphthylene	(b)	208-96-8	-	1.71E-09	9.23E-06	5.06E-06	-	-	2.96E-06	3.04E-07	2.25E-08	1.06E-05	1.47E-06
Anthracene	(b)	120-12-7	-	2.29E-09	1.23E-06	1.87E-06	-	-	3.95E-06	4.05E-07	3.00E-08	3.90E-06	5.44E-07
Benz(a)anthracene	(b)	56-55-3	-	1.71E-09	6.22E-07	1.68E-06	-	-	2.96E-06	3.04E-07	2.25E-08	3.51E-06	4.89E-07
Benzo(a)pyrene (PAH)	(b)	50-32-8	-	1.14E-09	2.57E-07	1.88E-07	-	-	1.97E-06	2.03E-07	1.50E-08	3.92E-07	5.47E-08
Benzo(b)fluoranthene	(b)	205-99-2	-	1.71E-09	1.11E-06	9.91E-08	-	-	2.96E-06	3.04E-07	2.25E-08	2.07E-07	2.89E-08
Benzo(g,h,i)perylene	(b)	191-24-2	-	1.14E-09	-	4.89E-07	-	-	1.97E-06	2.03E-07	1.50E-08	1.02E-06	1.42E-07
Benzo(k)fluoranthene	(b)	207-08-9	-	1.71E-09	2.18E-07	1.55E-07	-	-	2.96E-06	3.04E-07	2.25E-08	3.23E-07	4.51E-08
Chrysene	(b)	218-01-9	-	1.71E-09	1.53E-06	3.53E-07	-	-	2.96E-06	3.04E-07	2.25E-08	7.37E-07	1.03E-07
Dibenz(a,h)anthracene	(b)	53-70-3	-	1.14E-09	3.46E-07	5.83E-07	-	-	1.97E-06	2.03E-07	1.50E-08	1.22E-06	1.70E-07
Fluoranthene		206-44-0	-	2.86E-09	4.03E-06	7.61E-06	-	-	4.94E-06	5.07E-07	3.75E-08	1.59E-05	2.22E-06
Fluorene		86-73-7	-	2.67E-09	1.28E-05	2.92E-05	-	-	4.61E-06	4.73E-07	3.50E-08	6.09E-05	8.50E-06
Indeno(1,2,3-cd)pyrene	(b)	193-39-5	-	1.71E-09	4.14E-07	3.75E-07	-	-	2.96E-06	3.04E-07	2.25E-08	7.83E-07	1.09E-07
Phenanthrene		85-01-8	-	1.62E-08	4.08E-05	2.94E-05	-	-	2.80E-05	2.87E-06	2.13E-07	6.14E-05	8.56E-06
Pyrene		129-00-0	-	4.76E-09	3.71E-06	4.78E-06	-	-	8.23E-06	8.45E-07	6.26E-08	9.97E-06	1.39E-06
Total POM Emissions								**3.59E-04**					
Mercury													
Mercury		7439-97-6	-	2.48E-07	-	-	3.00E-06	-	4.28E-04	4.39E-05	3.25E-06	6.26E-06	8.73E-07
Total Mercury Emissions								**4.82E-04**					
Dioxins and Furans													
Not Expected to be Emitted													
HAP Metals													
Arsenic		7440-38-2	-	1.90E-07	-	-	4.00E-06	-	3.29E-04	3.38E-05	2.50E-06	8.35E-06	1.16E-06
Beryllium	(b)	7440-41-7	-	1.14E-08	-	-	3.00E-06	-	1.97E-05	2.03E-06	1.50E-07	6.26E-06	8.73E-07
Cadmium		7440-43-9	-	1.05E-06	-	-	3.00E-06	-	1.81E-03	1.86E-04	1.38E-05	6.26E-06	8.73E-07
Lead	(e)	7439-92-1	-	4.76E-07	-	-	9.00E-06	-	8.23E-04	8.45E-05	6.26E-06	1.88E-05	2.62E-06
Manganese		7439-96-5	-	3.62E-07	-	-	6.00E-06	-	6.25E-04	6.42E-05	4.76E-06	1.25E-05	1.75E-06
Nickel		7440-02-0	-	2.00E-06	-	-	3.00E-06	-	3.45E-03	3.55E-04	2.63E-05	6.26E-06	8.73E-07
Total HAP Metal Emissions								**7.91E-03**					
All Other Air Toxics													
1,3-Butadiene	(b)	106-99-0	4.30E-07	-	-	3.91E-05	-	7.24E-03	-	-	-	8.16E-05	1.14E-05
Acetaldehyde		75-07-0	4.00E-05	-	2.52E-05	7.67E-04	-	0.67	-	-	-	1.60E-03	2.23E-04
Acrolein	(b)	107-02-8	6.40E-06	-	7.88E-06	9.25E-05	-	0.11	-	-	-	1.93E-04	2.69E-05
Benzene		71-43-2	1.20E-05	2.00E-06	7.76E-04	9.33E-04	-	0.20	3.45E-03	3.55E-04	2.63E-05	1.95E-03	2.72E-04
Butane		106-97-8	-	2.00E-03	-	-	-	-	3.45	0.35	0.03	-	-
Cobalt		7440-48-4	-	8.00E-08	-	-	-	-	1.38E-04	1.42E-05	1.05E-06	-	-
Ethylbenzene		100-41-4	3.20E-05	-	-	-	-	0.54	-	-	-	-	-
Formaldehyde	(c)	50-00-0	2.76E-04	2.76E-04	7.89E-05	1.18E-03	-	4.64	0.48	0.05	3.62E-03	2.46E-03	3.44E-04
Hexane (n)	(d)	110-54-3	-	1.24E-06	-	-	-	-	2.14E-03	2.20E-04	1.63E-05	-	-
Naphthalene		91-20-3	1.30E-06	5.81E-07	1.30E-04	8.48E-05	-	0.02	1.00E-03	1.03E-04	7.63E-06	1.77E-04	2.47E-05
Propylene Oxide	(b)	75-56-9	2.90E-05	-	-	-	-	0.49	-	-	-	-	-
Toluene		108-88-3	1.30E-04	3.24E-06	2.81E-04	4.09E-04	-	2.19	5.59E-03	5.74E-04	4.25E-05	8.53E-04	1.19E-04
Vanadium		7440-62-2	-	2.19E-06	-	-	-	-	3.78E-03	3.89E-04	2.88E-05	-	-
Xylenes		1330-20-7	6.40E-05	-	1.93E-04	2.85E-04	-	1.08	-	-	-	5.95E-04	8.30E-05
Total Other Air Toxics Emissions								**14.34**					

[a] The combustion turbine and the duct burners vent to a common HRSG stack.

[b] Emissions factors are based on method detection limits from AP-24 Chapter 1.4, Chapter 3.1, Chapter 3.3, or Chapter 3.4.

[c] Formaldehyde standard in 40 CFR Part 63, Subpart YYYY (0.091 parts per million, volumetric dry [ppmvd] @ 15% oxygen [O2]).

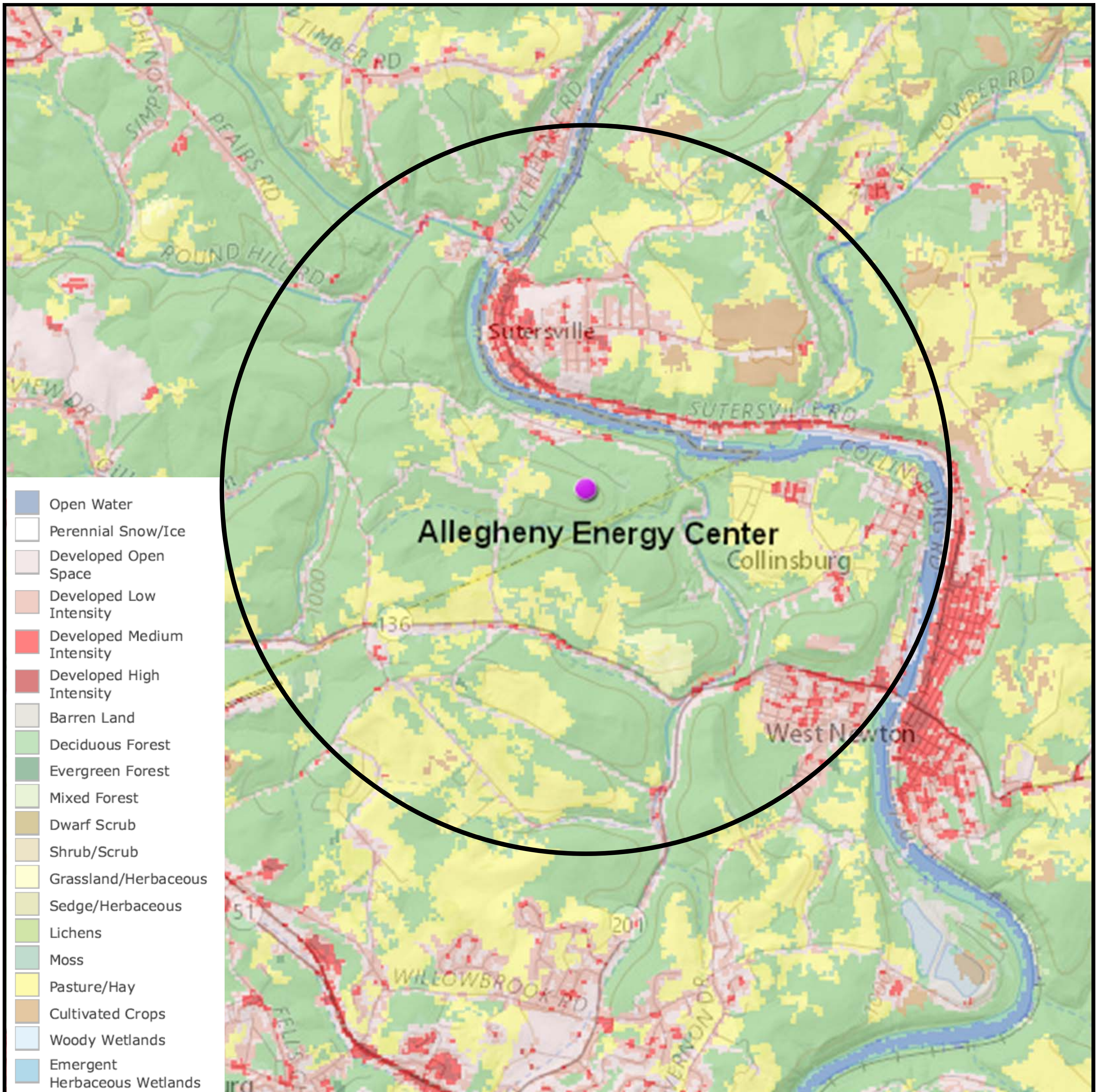
[d] The AP-42 emissions factor for hexane from natural gas combustion (AP-42 Chapter 1.4 Table 1.4-3 (7/98)) has been designated as poor (i.e. "E" rating). This hexane emissions factor is considered unreasonably high. Therefore, a more realistic hexane emissions factor is being used. The hexane emissions factor is provided in Ventura County Air Pollution Control District document AB2588 AB 2588 - Combustion Emission Factors.

[e] Lead emissions factor is from AP-42, converted from lb/MMscf to lb/MMBtu.

Table 6-6
Summary of Physical Stack Characteristics
Invenergy LLC - Allegheny Energy Center

Source	Case Number	AERMOD ID	CT Load	HRSG Duct Burner	Ambient Temperature	UTM Easting	UTM Northing	Base Elevation	Stack Height	Stack Temperature	Stack Velocity	Stack Diameter
			%	Fired/ Unfired	°F	(m)	(m)	(m)	(m)	(K)	(m/s)	(m)
Auxiliary Boiler	N/A	AUXBOIL	N/A	N/A	N/A	602,449.2	4,453,431.3	309.40	10.67	405.37	9.28	1.2
Dew Point Heater	N/A	DEWPT	N/A	N/A	N/A	602,247.0	4,453,313.1	309.40	7.62	622.04	6.35	0.5
Emergency Generator	N/A	EGEN	N/A	N/A	N/A	602,419.7	4,453,445.1	309.40	4.57	753.15	46.29	0.5
Fire Water Pump	N/A	FP	N/A	N/A	N/A	602,328.7	4,453,506.9	309.40	3.81	789.26	36.22	0.2
HRSG[a]	15	W100FA	100%	Operating	-26	602,441.6	4,453,386.8	309.40	54.86	341.76	23.4	6.7
	17	W100UA	100%	Off	-26					350.48	23.86	
	18	W50U	50%	Off	-26					339.87	15.31	
	4	W100FB	100%	Operating	9.0					341.76	23.32	
	5	W100UB	100%	Off	9					349.82	23.77	
	1	A100F	100%	Operating	53					341.82	22.85	
	2	A100U	100%	Off	53					349.98	23.31	
	11	S100FA	100%	Operating	88					347.93	22.84	
	13	S100U	100%	Off	88					354.15	22.50	
	14	S37U	37%	Off	88					343.09	13.08	
	21	S100FB	100%	Operating	102					350.82	21.13	
	23	S100UC	100%	Off	102					357.37	21.42	
	24	S41U	41%	Off	102					349.43	13.53	
	N/A	CS	N/A	N/A	N/A					344.26	17.74	
	N/A	WS	N/A	N/A	N/A					344.26	17.74	
	N/A	HS	N/A	N/A	N/A					344.26	20.05	

[a] The combustion turbine and the duct burners vent to a common HRSG stack.



3 km radius from AEC

N

0 1.5 3

kilometers

Allegheny Energy Center
Elizabeth Township, Allegheny County, PA

Figure 6-1
Proposed Allegheny Energy Center
3 km Land Use Analysis

Structure Location

Source Location

Receptor

Fence Line Receptor

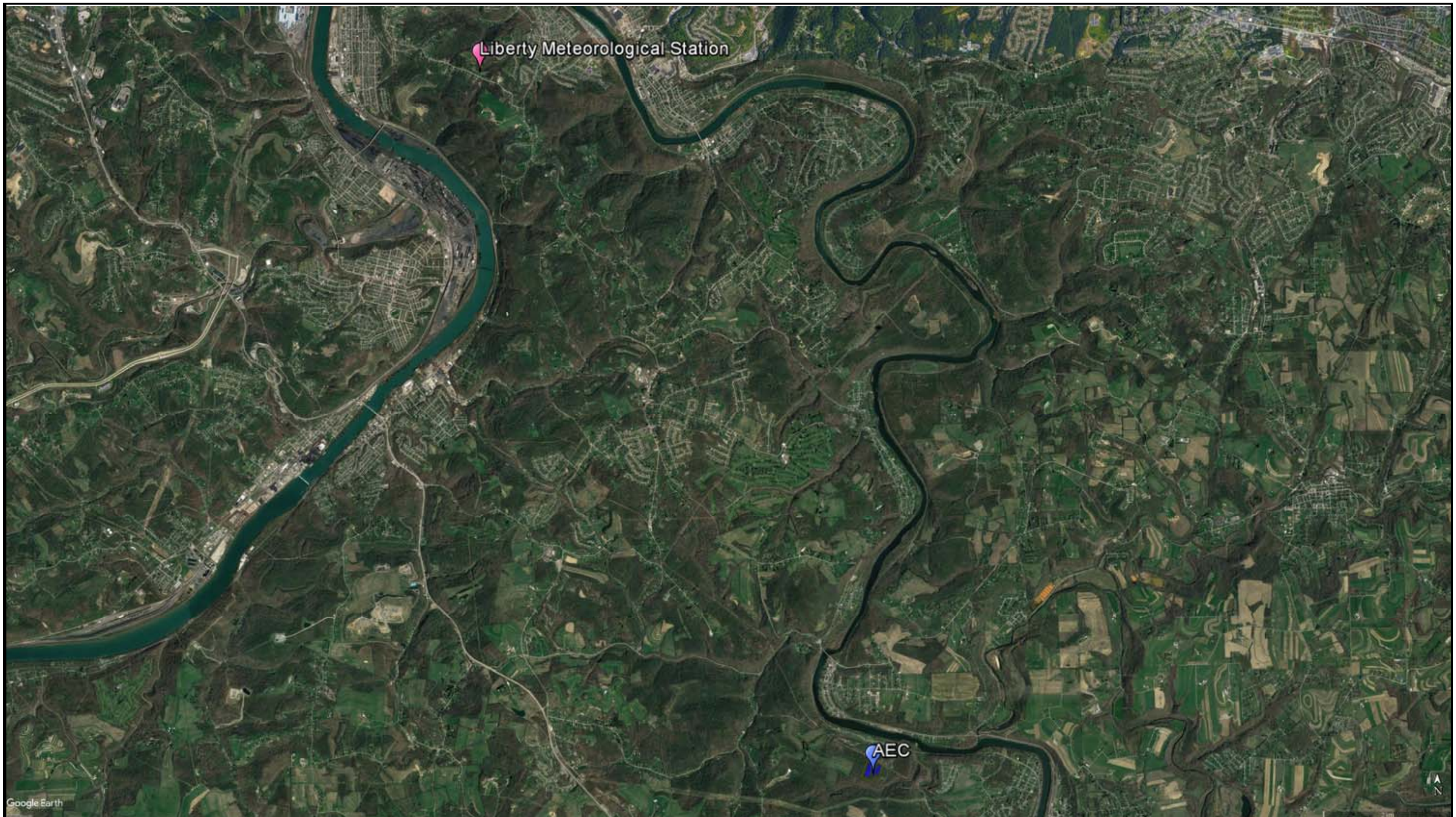
0 800 1600

Meters

N

Allegheny Energy Center
Elizabeth Township, Allegheny County, PA

Figure 6-2
Proposed Allegheny Energy Center
Inner Receptor Grid

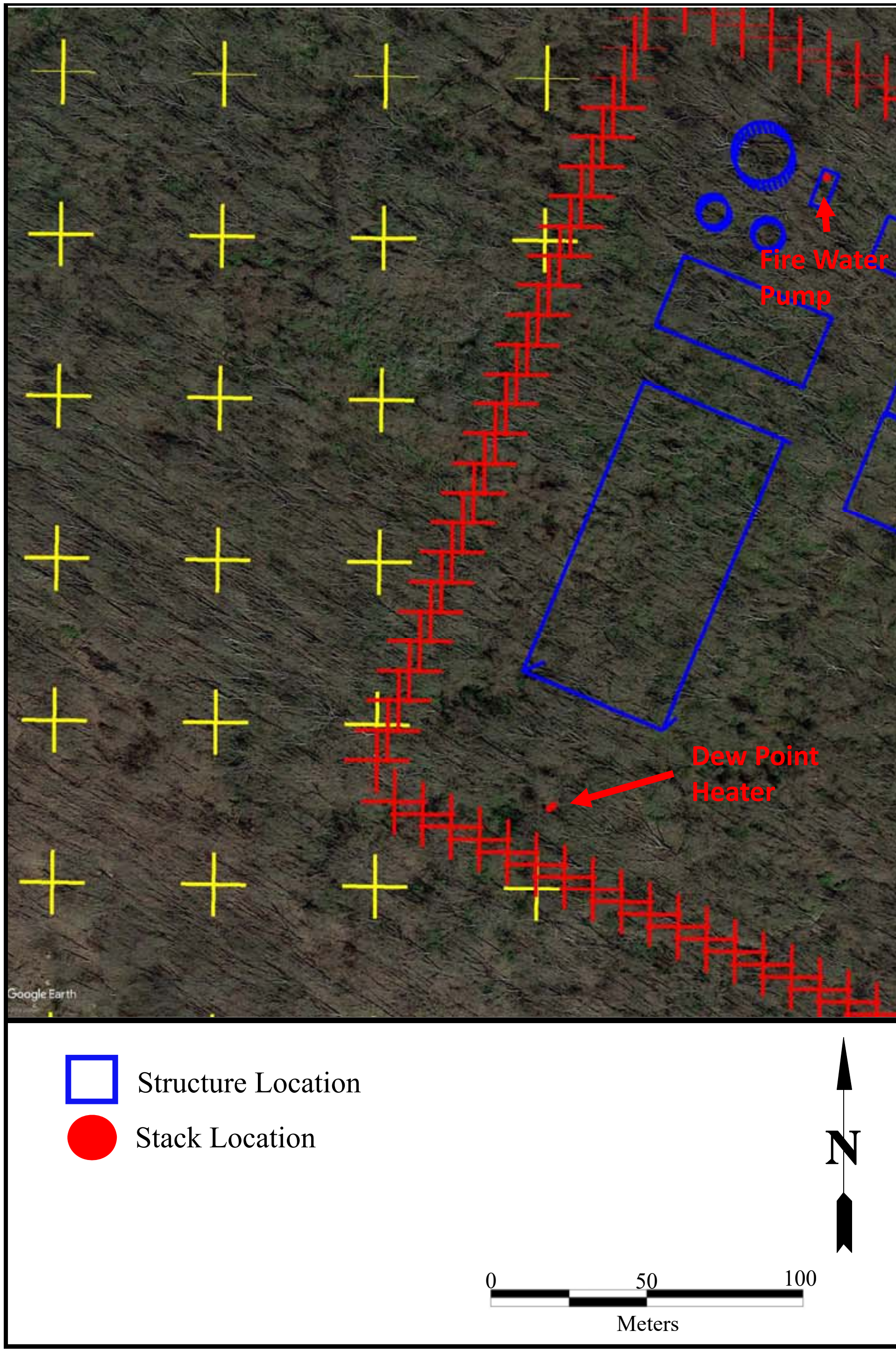


0 2 4
kilometers

N

Allegheny Energy Center
Elizabeth Township, Allegheny County, PA

Figure 6-3
Regional Map of Meteorological Station and the Proposed Allegheny Energy Center



Allegheny Energy Center
Elizabeth Township, Allegheny County, PA

Figure 6-4
Proposed Allegheny Energy Center
Building Downwash Analysis

Table 6-7
Diurnal Seasonal 3rd Highest 3-Year Average NO_2 Concentrations
Invenergy LLC - Allegheny Energy Center

Hour	NO_2 Concentration (ppb) [(a)]			
	Winter	Spring	Summer	Autumn
1	30.0	29.3	18.3	23.3
2	28.7	28.0	15.0	21.0
3	29.0	29.3	14.0	20.7
4	28.7	27.7	13.3	19.3
5	28.0	27.3	15.0	20.0
6	29.3	27.0	15.3	20.3
7	30.3	29.3	16.0	21.7
8	32.7	28.0	15.7	23.0
9	32.0	28.0	11.7	22.0
10	32.3	19.7	8.7	24.0
11	28.7	12.3	7.3	19.7
12	27.0	14.3	7.7	13.7
13	22.0	13.3	7.0	14.0
14	19.7	10.0	7.0	18.0
15	17.3	9.7	6.7	12.3
16	18.3	10.0	7.7	14.0
17	23.7	10.7	7.7	15.0
18	24.3	14.7	8.3	16.0
19	26.0	17.3	8.3	19.7
20	28.0	22.3	9.3	22.7
21	27.7	23.0	10.7	23.3
22	29.0	27.0	14.3	23.7
23	29.0	26.0	17.3	22.3
24	29.3	28.7	17.0	21.7

[(a)] NO_2 concentrations were measured at the Charleroi, Washington, PA ambient air monitor (AirData Monitoring Site ID: 42-125-0005) from January 1, 2012 to December 31, 2014.

[(b)] 1 part per billion (ppb) of NO2 = 1.88 micrograms per cubic meter (µg/m3).

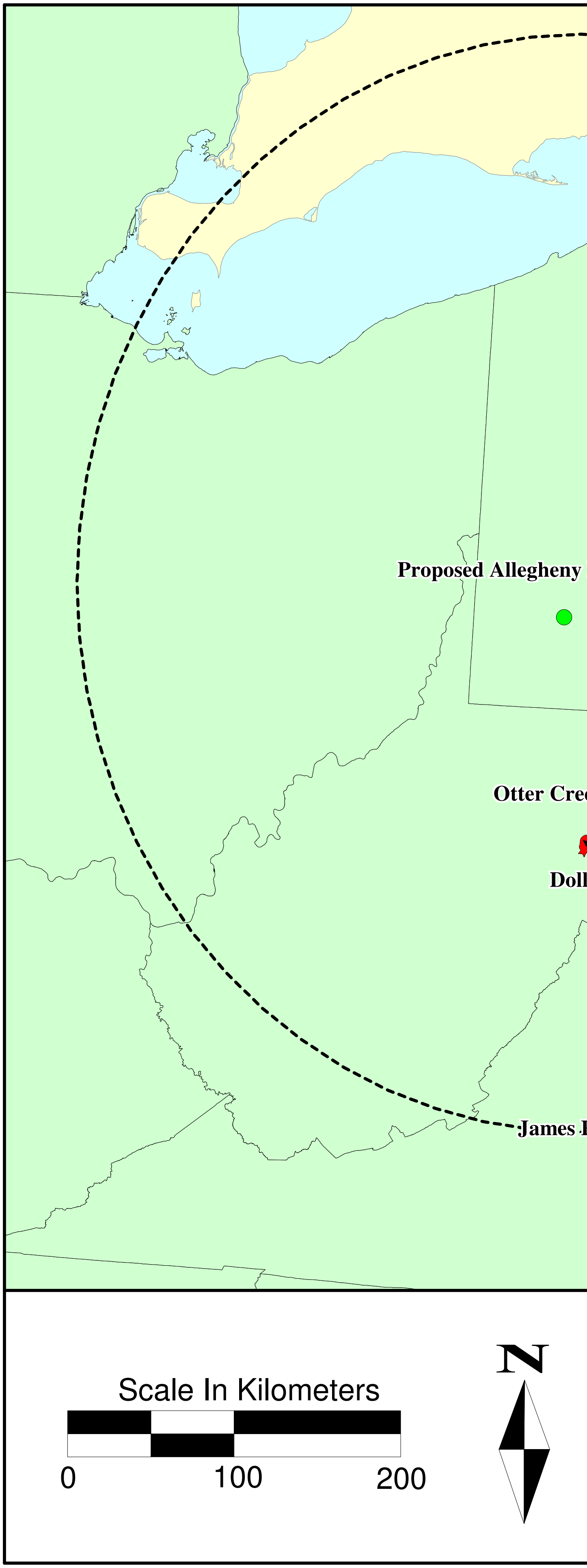


Figure 6-5
Location of Class I Areas
Within 300 km of the
Proposed Allegheny
Energy Center

Table 6-8

Class I Air Quality Related Values Evaluation - Q/d Analysis

Invenergy LLC - Allegheny Energy Center

Total Project Emissions [a] (TPY)				
NO_X	SO_2	PM_{10}		H_2SO_4
145.7	24.4	90.7		22.3
Total NO_X, SO_2, PM_{10}, and H_2SO_4 Project Emissions (Q):				283.1
Total 24-hour Annualized Project Emissions [b]				
NO_X	SO_2	PM_{10}		H_2SO_4
135.5	24.5	92.5		17.5
Total NO_X, SO_2, PM_{10}, and H_2SO_4 Project Emissions (Q):				270.0
Class I Area	**Distance to Class I Area (d, km)**	**Q/d[c]**		**Q/d <10? [d]**
		Annual	**24-Hour Annualized**	
Otter Creek Wilderness Area	137.0	2.1	2.0	Yes
Dolly Sods Wilderness Area	137.0	2.1	2.0	Yes
Shenandoah National Park	236.0	1.2	1.1	Yes
James River Face Wilderness Area	295.0	1.0	0.9	Yes

(a) Total annual project emissions.

(b) Total 24-hour annualized emissions are estimated based on the maximum hourly emissions from the combustion turbines (CT) and dew point heaters operating for 8,760 hours per year. Additional ancillary equipment (i.e., auxiliary boiler, emergency generators, and fire pump) will not operate at the same time as the CT and therefore were not included.

(c) Total annual emissions for comparison to deposition Air Quality Related Value (AQRV) and worst case 24-hour annualized emission for comparison to visibility AQRV.

(d) Federal Land Manager's (FLM) Air Quality Related Values Work Group (FLAG) guidance, suggests that agencies will consider a source located greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total NO_X, SO_2, PM_{10}, and H_2SO_4 annual emissions (in tons per year, based on 24-hour maximum allowable emissions), divided by the distance (in km) from the Class I area (Q/d) is less than 10.

Table 6-9
Summary of Load Analyses, Worst-Case Emissions and Design Operating Conditions
Invenergy LLC - Allegheny Energy Center

Emission Unit	Pollutant	Averaging Period	Case	Case	Case Number	Load	Ambient Temperature (°F)
Combustion Tubine 1	PM_{10}	24-hr	Worst-Case	S37U	14	37%	87
		Annual		S37U	14	37%	87
	$PM_{2.5}$	24-hr		S37U	14	37%	87
		Annual		S37U	14	37%	87
	NO_X	1-hr		CS	Cold Start	Cold Start	N/A
		Annual		W100FB	50	100%	9
	CO	1-hr		CS	-	N/A	N/A
		8-hr		CS	-	N/A	N/A
	PM_{10}	24-hr	Design	CTPTE	1	100%	53
		Annual					
	$PM_{2.5}$	24-hr					
		Annual					
	NO_X	1-hr					
		Annual					
	CO	1-hr					
		8-hr					

Table 6-10
Results of the Class I Significant Impact Level Modeling Analysis
Invenergy LLC - Allegheny Energy Center

Pollutant	Averaging Period	Form	Scenario	Class I SIL ($\mu g/m^3$)	Modeled Concentration ($\mu g/m^3$)	Modeled Concentration Less Than Class I SIL (Y/N)
NO_2	Annual	Maximum	Worst Case	0.1	1.00E-02	Yes
			Design		1.06E-02	Yes
PM_{10}	24-Hour		Worst Case	0.32	9.21E-02	Yes
			Design		1.03E-01	Yes
	Annual		Worst Case	0.2	6.32E-03	Yes
			Design		7.13E-03	Yes
$PM_{2.5}$	24-Hour		Worst Case	0.27	5.98E-02	Yes
			Design		6.63E-02	Yes
	Annual		Worst Case	0.05	6.31E-03	Yes
			Design		7.12E-03	Yes

Table 6-11
Ambient Monitor Summary
Invenergy, LLC - Allegheny Energy Center

Monitor				Averaging Period	Form	2015	2016	2017	Average	Maximum	NAAQS	Difference	Class II SILs
State	County	City	ID			µg/m^3							
PA	Allegheny	Pittsburgh	42-003-0008	1-Hour	High Second-High	1,489.3	1,603.8	2,062.1	**N/A**	**2,062.1**	**40,000**	**37,938**	**2,000**
				8-Hour	High Second-High	1,260.2	1,374.7	1,260.2	**N/A**	**1,374.7**	**10,000**	**8,625**	**500**
PA	Washington	Charleroi	42-125-0005	Annual	Maximum	51.0	44.0	43.0	**N/A**	**51.0**	**100**	**49.0**	**1.0**
PA	Allegheny	Clairton	42-003-3007	24-Hour	98th Percentile	26.0	20.0	19.0	**21.7**	**N/A**	**35**	**13.3**	**1.2**
				Annual	Average	10.4	9.3	9.8	**9.8**	**N/A**	**12**	**2.2**	**0.2**
PA	Allegheny	Clairton	42-003-3007	24-Hour	High Second-High	34.0	27.0	28.0	**N/A**	**34.0**	**150**	**116.0**	**5.0**

Table 6-12
Results of the Class II Significant Impact Level Modeling Analysis
Invenergy LLC - Allegheny Energy Center

Pollutant	Averaging Period	Form	Scenario	Class II SIL ($\mu g/m^3$)	Modeled Concentration ($\mu g/m^3$)	Modeled Concentration Less Than Class II SIL (Y/N)
CO	1-Hour	Maximum	Worst Case	2,000	639.56	Yes
			Design		639.56	Yes
	8-hour		Worst Case	500	363.09	Yes
			Design		363.09	Yes
NO_2	1-Hour		Worst Case	7.5	28.95	No
			Design		23.41	No
	Annual		Worst Case	1	0.42	Yes
			Design		0.43	Yes
PM_{10}	24-Hour		Worst Case	5	1.60	Yes
			Design		1.60	Yes
	Annual		Worst Case	1	0.09	Yes
			Design		0.08	Yes
$PM_{2.5}$	24-Hour		Worst Case	1.2	0.99	Yes
			Design		0.99	Yes
	Annual		Worst Case	0.2	0.08	Yes
			Design		0.07	Yes

Table 6-13
Results of the 1-Hour NO_2 NAAQS Modeling Analysis
Invenergy LLC - Allegheny Energy Center

Pollutant	Averaging Period	Form	Scenario	NAAQS ($\mu g/m^3$)	Project[a] ($\mu g/m^3$)	Background[b] ($\mu g/m^3$)	Local Sources ($\mu g/m^3$)	Modeled + Monitored Concentration ($\mu g/m^3$)	Modeled Concentration Less Than NAAQS[c] (Y/N)
NO_2	1-Hour	Five Year Average of 98th Percentile of Daily Maximum 1-Hour Concentrations	Worst Case	188	7.2E-03	43.6	7097.3	7140.9	No
			Design		3.9E-03	43.6	7097.3	7140.9	No

[a] The maximum 8th high impact from Project-only sources is 18.6 $\mu g/m^3$ for the worst case operating scenario, and16.1 $\mu g/m^3$ for the design scenario.
[b] NO_2 seasonal diurnal background concentrations are combined with modeled concentration for each of the five years of meteorological data in the post processing stage of the AERMOD air dispersion model.

Table 6-14

Inhalation Toxicity Values[(a)]

Invenergy LLC - Allegheny Energy Center

Air Toxic	CAS Number	Carcinogenic Risk		Non-Carcinogenic Risk	
		Inhalation Unit Risk Factor (URF) ($m^3/\mu g$)	Reference	Reference Concentration (RfC) ($\mu g/m^3$)[(b)]	Reference
All Other Air Toxics					
1,3-Butadiene	106-99-0	3.00E-05	U.S. EPA IRIS	2.0	U.S. EPA IRIS
Acetaldehyde	75-07-0	2.20E-06	U.S. EPA IRIS	9.0	U.S. EPA IRIS
Acrolein	107-02-8	N/A		0.02	U.S. EPA IRIS
Benzene	71-43-2	7.80E-06	U.S. EPA IRIS	30.0	U.S. EPA IRIS
Cobalt	7440-48-4	9.00E-03	PPRTV	6.00E-03	PPRTV
Ethylbenzene	100-41-4	2.50E-06	CAL EPA	1,000	U.S. EPA IRIS
Formaldehyde	50-00-0	1.30E-05	U.S. EPA IRIS	9.83	ATSDR
Hexane (n)	110-54-3	N/A		700	U.S. EPA IRIS
Naphthalene	91-20-3	3.40E-05	CAL EPA	3	U.S. EPA IRIS
Propylene Oxide	75-56-9	3.70E-06	U.S. EPA IRIS	30	U.S. EPA IRIS
Toluene	108-88-3	N/A		5,000	U.S. EPA IRIS
Vanadium	7440-62-2	N/A		1.00E-01	ATSDR
Xylenes	1330-20-7	N/A		100	U.S. EPA IRIS

(a) Air toxics thresholds were assessed using the following hierarchy of sources:

Tier 1 – U.S. EPA's IRIS.

Tier 2 – U.S. EPA's Provisional Peer Reviewed Toxicity Values (PPRTVs). The Office of Research and Development/National Center for Environmental Assessment/Superfund Health Risk Technical Support Center (STSC) develops PPRTVs on a chemical specific basis when requested by U.S. EPA's Superfund program.

Tier 3 – Other toxicity values. Tier 3 includes additional U.S. EPA and non-EPA sources of toxicity information. Sources of Tier 3 values include: California Environmental Protection (Cal EPA) Reference Exposure Levels (RELs), Agency for Toxic Substances and Disease Registry (ATSDR) Minimal Risk levels (MRLs), and Health Effects Assessment Summary Tables (HEAST) toxicity values.

(b) RfC values are adjusted from mg/m^3 to $\mu g/m^3$ for comparison with modeled concentrations.

Table 6-15

Air Toxics Risk Evaluation

Invenergy LLC - Allegheny Energy Center

Air Toxic	CAS Number	Maximum Modeled Annual Concentration ($\mu g/m^3$)	Carcinogenic Risk	Non-Carcinogenic Risk
			Maximum Individual Carcinogenic Risk (MICR)[a]	Hazard Quotient (HQ)[b]
All Other Air Toxics				
1,3-Butadiene	106-99-0	8.37E-06	2.51E-10	4.19E-06
Acetaldehyde	75-07-0	7.79E-04	1.71E-09	8.65E-05
Acrolein	107-02-8	1.25E-04	-	6.23E-03
Benzene	71-43-2	2.70E-04	2.11E-09	9.00E-06
Cobalt	7440-48-4	3.59E-06	3.23E-08	5.98E-04
Ethylbenzene	100-41-4	6.23E-04	1.56E-09	6.23E-07
Formaldehyde	50-00-0	1.15E-02	1.49E-07	1.17E-03
Hexane (n)	110-54-3	4.00E-05	-	5.71E-08
Naphthalene	91-20-3	4.00E-05	1.36E-09	1.33E-05
Propylene Oxide	75-56-9	5.65E-04	2.09E-09	1.88E-05
Toluene	108-88-3	2.58E-03	-	5.16E-07
Vanadium	7440-62-2	7.00E-05	-	7.00E-04
Xylenes	1330-20-7	1.25E-03	-	1.25E-05
			Cumulative MICR	**Cumulative Hazard Index (HI)**
			1.91E-07	**8.84E-03**
		ACHD Threshold	1.00E-05	2.0
		Exceeds ACHD Threshold?	No	No

[a] Carcinogenic Risk is calculated using the following equation:

$$Maximum\ Individual\ Carcinogenic\ Risk (MICR) = Modeled\ Maximum\ Annual\ Concentration * Inhalation\ Unit\ Risk\ Factor\ (URF)$$

[b] Non-Carcinogenic Risk is calculated using the following equation:

$$Hazard\ Quotient = \frac{Modeled\ Maximum\ Annual\ Concentration}{Reference\ Concentration\ (RfC)}$$

Environmental Justice Area

Allegheny Energy Center

N

0 1.5 3

kilometers

Allegheny Energy Center
Elizabeth Township, Allegheny County, PA

Figure 6-6
Environmental Justice Areas and the Proposed Allegheny Energy Center

7. ALTERNATIVES ANALYSIS

As a new major stationary source being sited in a nonattainment area, AEC prepared an analysis of alternatives to the project. The alternatives analysis demonstrates that the benefits of the currently proposed scope of the project offset and outweigh alternatives to the proposed project. The analysis evaluated alternatives to the current project scope for the following five items:

- Physical location of the proposed project
- Size of the project
- Approach selected to generate electricity
- Type of emissions controls evaluated
- Economic, social, and environmental impacts

This alternatives analysis is required because the proposed location of the source is classified as nonattainment with the NAAQS for O_3. As noted previously, the status of O_3 nonattainment is related to OTR classification and not actual monitored violations of the O_3 NAAQS immediately surrounding the proposed project site. The alternatives analysis focused on the three nonattainment pollutants as they relate to the Project and is consistent with the regulations at §2102.06.

7.1 ALTERNATE PROJECT LOCATIONS

There are many factors that must be considered when selecting a location to construct an electric generating facility. In identifying and screening potential project sites, several key factors and criteria were considered in order to meet Project requirements. These factors included:

1. Proximity to electric transmission lines, fuel pipelines, and water sources (key infrastructure);

2. Land use compatibility (e.g., zoning and compatible neighboring land uses);

3. Adequate site size and topography (providing a minimum of 30 acres that are or can be feasibly adjusted to be relatively flat to accommodate required equipment and support facilities, with adequate buffering to neighboring properties);

4. Site environmental suitability (building acreage, minimum wetland disturbance; avoidance of impacts to protected species; avoidance/minimization of impacts to special protection waters; suitable and stable foundation conditions; etc.); and

5. Real estate availability (i.e., main site landowner willingness to consider sale and potential issues of obtaining easements for supporting off-site infrastructure, such as pipelines).

Applying these factors, AEC identified five candidate sites – Muskingham Township, OH, Ravenswood, WV, Wythe County, VA, Van Buren, MI, and Elizabeth Township, Allegheny County, PA – as meeting the initial screening criteria. Upon further investigation the Muskingham Township, OH it was eliminated from consideration because the real estate price was not economically feasible for the project. The Wythe County, VA and Van Buren, MI sites were removed from consideration based on limited availability of water. The Ravenswood, WV site transmissions costs from the gas pipeline to the site were cost prohibitive and therefore was also removed from consideration.

The proposed location will require reduced infrastructure upgrades relative to the other proposed sites. Specifically, an electrical transmission line less than 1-mile in length will be constructed. Gas supply lateral to the site less than 1-mile in length will be constructed. Access roads to the site will be repaired and upgraded to support construction and operating traffic as well as future public use. Water supply and sewer discharge will be municipal and will require some upgrades to existing system to support the project resulting in improved water pressure/supply reliability to neighboring properties.

7.2 ALTERNATE PROJECT SIZE

AEC has designed the project to produce 639 MW of electric output as a baseload source. The size of the project is based on a consideration and weighing of the regional demand for electricity, the local electrical transmission capacity, natural gas transport capability, combined cycle generation technologies, and the financial return projected for facilities with various sizes of generating capacity.

5,605 MW in 2016. Combined with a projected 0.4% growth in net energy demand, the proposed project will be part of the replacement of existing electric generation and supply of additional demand in the PJM region. PJM is projecting a summer peak load demand of 157,635 MW in 2028 for the region. Thus, there is a need for the proposed project to make-up retiring electric generation and demand growth.

7.3 ALTERNATE APPROACH TO ELECTRIC GENERATION

Invenergy has extensive experience with the development of energy projects related to natural gas as well as renewable energy (e.g., solar and wind). Therefore, Invenergy's experience served as the basis for the analysis of alternate approaches for the generation of electricity. Invenergy considered cost, reliability and environmental impacts as the criteria to perform the comparisons of alternate approaches to electrical generation.

Combined cycle generating stations are a reliable form of electric generation. Whereas electric generation from solar and wind are dependent on meteorological factors and time of day, the combustion of natural gas is a consistent and reliable approach for generating baseload electricity. Additionally, combined cycle plants can manage variability in the demand for electric generation better than other forms (e.g., standard boiler combustion, nuclear). Combustion turbines can react to electric demand in a matter of minutes. Therefore, a combustion turbine represents a greater value to the regional electrical grid than solar or wind generated electricity that is not dispatchable.

If renewable energy were used to generate the same amount of electricity as the proposed Facility, the physical footprint of the site would need to be much larger. If a solar energy farm were placed on the currently proposed footprint of the project site, approximately 2.3 MW of electricity would be generated. If a wind farm was considered in place of the proposed Facility, it would be unlikely that the optimal siting criteria for wind farms would be met. In the eastern U.S., wind farms are sited along mountain ridges or at the end of long open fetches of wind (e.g., along the shorelines of the Great Lakes, a few miles off the continental coastline). In addition, at 3 MW per wind turbine (a high-end output), more than 200 wind turbines would be required to produce an equivalent amount of electric output as the proposed Facility. The closest wind farms are located more than 100 kilometers (62 miles) away from the proposed site include between 30 and 50 wind turbines. The currently proposed site is not compatible with alternative renewable energy generation options, nor are the renewable energy options as capable of producing the required electric output.

The proposed project represents an efficient method to generate electricity especially when compared to older electric generating facilities that are still in operation. The selected equipment will be among the newest of available gas and steam turbine technology. Therefore, the project can be dispatched before older, less efficient electric generating facilities and will thereby reduce the regional level of air pollution including CO_2.

The cost of construction and development of a combined cycle generating station is less than solar and wind farms. The U.S. Energy Information Administration's 2019 annual energy outlook summarized the construction and development costs by region of the country. For the Pennsylvania region, the development and construction costs for solar and wind farms are more than twice the costs for natural gas combined cycle projects. Thus, the use of an alternate approach for the generation of electrical power is not a financially beneficial strategy.

Finally, the use of coal and fuel oil would have greater environmental impacts than natural gas and are not technologies that Invenergy pursues as a developer. Therefore, no consideration was given to these fuels.

7.4 ALTERNATE APPROACH TO CONTROLLING EMISSIONS

Project emissions totals for NO_X and VOC are the only pollutants that trigger NNSR applicability for this facility. NOx emissions trigger NNSR applicability as precursors for O_3 and $PM_{2.5}$ formation while VOC emissions trigger NNSR applicability as a precursor for O_3 formation. AEC has reviewed the approach to controlling NO_X and VOC emissions to assess whether there are alternatives to the proposed emissions controls.

7.4.1 Alternate Controls for NO_X Emissions

As noted in Section 5, LAER for the CT is achieved with the use of efficient combustion design as part of the turbine itself including dry-low NO_X burner technology, good turbine operating practices to limit NO_X emissions, use of natural gas as a fuel, and then the use of SCR as post-combustion emissions control. There are no other proven alternate approaches to control NO_X emissions. Thus, NO_X emissions from the CT are controlled to the best level possible.

The control of NO_X emissions from the Auxiliary Boiler follows a similar approach to that of the CT. Specifically, a combination of efficient boiler design, use of natural gas, good boiler operating practices, and post combustion controls result in the lowest achievable level of NO_X emissions. A literature review determined that there are no other proven alternatives for the control of NO_X emissions, and thus the Auxiliary Boiler is controlled to the best level possible.

Unlike the CT, the Auxiliary Boiler is not being operated for the purpose of generating baseload electric output. The Auxiliary Boiler is being used to support the operation of the ST during start-ups and during other periods as required. This infrequent operating and limited operating schedule means that the Auxiliary Boiler is not a primary source of NO_X emissions at the facility.

The Dewpoint Heater, the Emergency Diesel Engine, and the Fire Pump Engine contribute minor sources of NO_X emissions for the overall Project. The Dewpoint Heater is physically small enough and designed such that post combustion control is not a technically feasible option. Specifically, there is no defined combustion exhaust stream that could be collected and routed for post combustion control. Also, the use of an electric Dewpoint Heater would require a much larger and more expensive piece of equipment. Typical industry standard is to use a gas-fired Dewpoint Heater for an application of this size. A Dewpoint Heater that utilizes waste heat from the CT or the Auxiliary Boiler is also not practical. There are periods when the CT is not operating and thus unable to provide waste heat. Waste heat from the Auxiliary Boiler would require significant capital expense for the installation of a steam line and condensate collection piping because the Auxiliary Boiler and the Dewpoint Heater are located on opposite corners of the site.

7.4.2 Alternate Controls for VOC Emissions

The CT is equipped with a CO catalyst that also functions to control VOC emissions. In addition to the CO catalyst, the CT is maintained with good operating practices to achieve a LAER limit. The use of a thermal oxidizer could be considered an alternate control of VOC emissions from the CT; however, there are technical and practical limitations that prevent a thermal oxidizer from being a viable alternate control device. First, a thermal oxidizer is not efficient at reducing already low concentrations of VOC, as will be the case with the CT at 1.5 ppm VOC. Second, there will be a very large air flow associated with the CT exhaust (approximately 1,710,000 acfm) and thermal oxidizers are typically designed to handle small exhaust stream flows (e.g., 20,000 acfm). Third, the use of a thermal oxidizer will increase the combustion emissions profile of the facility including NO_X emissions. Therefore, there are no feasible alternative controls to the proposed LAER determination that would be effective at reducing VOC emissions.

VOC emissions from the Auxiliary Boiler are limited through the engineering design of the boiler, the use of good combustion practices, and post combustion control with a CO catalyst, that can also control VOC emissions. As with the CT, the use of a thermal oxidizer as an alternate VOC emissions control device on the Auxiliary Boiler has technical and logistical limitations. The Auxiliary Boiler VOC concentration levels are extremely low at 10 ppm, which will not be efficiently reduced by a thermal oxidizer. The exhaust flow rate for the Auxiliary Boiler is compatible for a thermal oxidizer; however, the use of a thermal oxidizer will generate its own combustion emissions including NO_X emissions thus increasing the emissions profile of the facility. Therefore, a thermal oxidizer is not a feasible alternative to the proposed LAER determination for the Auxiliary Boiler.

Finally, there are no post combustion VOC controls for the Dewpoint Heater, the Emergency Diesel Generator, and the Fire Pump Engine. The size and anticipated usage of each of these three emissions units precludes the use of post combustion controls. The Dewpoint Heater exhaust stream is small and is not collected prior to exhausting. It would be impractical to add post combustion control. The two engines are permitted to operate for a maximum of 100 hours per year and are permitted to emit no more than 0.12 tpy combined VOC. Adding a CO catalyst for

90% control of 0.12 tons would only provide a 210 lb per year reduction in VOC emissions. The use of a CO catalyst as an alternative post combustion control measure would insignificantly affect VOC emissions from the Facility.

7.5 BENEFIT ANALYSIS

The proposed Project will provide multiple benefits to the local and regional public. These benefits will include economic, social, and environmental improvements to the public in Elizabeth Township, Allegheny County, and the Commonwealth of Pennsylvania. A description of the benefits of the project are summarized in the following subsections.

7.5.1 **Economic Benefits**

The proposed Project will provide a significant economic benefit to the local, regional, and statewide community. The construction of the proposed Facility will provide a significant economic boost to the surrounding area through the presence of temporary workers. There will be approximately 16 full-time positions at the Facility, with supporting services and contractors to be required once the Facility is operating. The Facility will also be a taxed facility at the local, county and statewide levels. As part of the air permitting process, AEC will be responsible for paying permitting fees as well as fees to offset emissions of NO_X and VOC. Finally, the generation of electricity via a modern combustion turbine is more efficient than older electric generating units, and thus the proposed Facility will provide an economic benefit indirectly by making the cost of electricity as inexpensive as possible.

7.5.2 **Social Benefits**

AEC will undertake several improvements to the surrounding infrastructure that will benefit the local community. The access road to the site and other surrounding roads will be repaired and upgraded to support construction and operating traffic, as well as future public use. The water supply and discharge for the Facility will require some upgrades to existing municipal water system to support the Project. Improvements to the water pressure and supply reliability to neighboring properties will occur. As a future member of the community, AEC anticipates playing an active role by sponsoring community events and local organizations.

7.5.3 Environmental Benefits

The proposed Project will provide environmental benefits since the proposed Project is a well-controlled and efficient approach for the generation of electricity. The environmental benefits will result from the displacement of older, less efficient, higher polluting electric generating facilities. Regional air quality of O_3, NO_2, SO_2, and $PM_{10}/PM_{2.5}$ will improve as higher polluting electric generating facilities are replaced. Although the proposed Project will be a source of local emissions, emissions of regulated NSR pollutants will be minimized by the use of BACT and LAER controls. Also, air quality modeling has been performed to confirm that emissions associated with the proposed Project will have a minimal effect on the surrounding air quality.

7.6 ALTERNATES ANALYSIS CONCLUSIONS

Relocating the proposed project site to an alternate area that is in attainment with the NAAQS for O_3, SO_2, and $PM_{2.5}$ would not result in a significant environmental benefit due to the efficient design of the Project. AEC has incorporated energy efficiency throughout the Facility from combustion devices, to plant operations, to the choice of fuel (i.e., natural gas) to minimize emissions. Emissions in general are controlled and reduced to the best degree possible using BACT. Emissions of NO_X and VOC are precursor pollutants with controls reflecting LAER technology. BACT and LAER for the Project include the use of combustion design, post-combustion control devices, and the application of good operating practices.

In addition, O_3 and $PM_{2.5}$ are regional air pollutants, which means that local sources of O_3 precursor emissions and local sources of direct $PM_{2.5}$ emissions and $PM_{2.5}$ precursor emissions are not likely to contribute to local concentration levels. Specifically:

- NO_X and VOC are the precursor emissions that form O_3 and NO_X, SO_2, and NH_3 are precursor emissions that form $PM_{2.5}$ as a result of atmospheric chemistry that occurs as these pollutants are transported 100 km or more downwind. Thus, emissions sources located outside of Allegheny County are contributors to the local O_3 and $PM_{2.5}$

concentrations. Also, because natural gas is the primary fuel that will be used at AEC, the amount of direct particulate matter that is emitted by AEC will be minimal.

- The amount of SO_2 that AEC will emit is very small since natural gas is the primary fuel that will be used at the facility. Thus, although AEC is located in an SO_2 nonattainment area, the choice of fuels will ensure that SO_2 emissions will be the least possible from a fuel combustion source.

Since the emissions profile from the Facility has been designed to be as minimally impacting as possible, locating the Facility in Allegheny County will have minimal impact on the local air quality related to O_3, $PM_{2.5}$, and SO_2. Air quality modeling and other analyses that have been conducted for the project also support a demonstration of minimal concentrations of O_3, $PM_{2.5}$, and SO_2 resulting from AEC emissions. Considering alternate project sites in place of the proposed site would not significantly improve the surrounding air quality since regional sources located outside of Allegheny County are likely contributors to existing O_3 and $PM_{2.5}$ concentration levels.

8. ALLEGHENY COUNTY HEALTH DEPARTMENT INSTALLATION PERMIT APPLICATION FORMS AND SUPPORTING INFORMATION

AEC is including a check payable to the "Allegheny County Air Pollution Control Fund" in the amount of $22,700, as established in §2102.10 of the ACHD Rules and Regulations, Article XXI. This fee covers the Installation Permit Fee for sources subject to NSPS, NESHAP, or MACT Standards and also includes the Annual Installation Permit Administration fee.

The following appendices provide supporting information for the Installation Permit Application:

Appendix A – Allegheny County Health Department Installation Permit Application Form

Appendix B – Compliance Review Form

Appendix C – Air Emissions Supporting Calculations

Appendix D – LAER/BACT Supporting Data

Appendix E – Vendor Information

Appendix F – Air Quality Modeling Information

Appendix G – Acid Rain and CSAPR Application Forms

Appendix H – Fugitive Dust Prevention and Control Plan

Appendix I – State Notifications

APPENDIX A –
ALLEGHENY COUNTY HEALTH DEPARTMENT INSTALLATION PERMIT APPLICATION FORM

APPENDIX B –
COMPLIANCE REVIEW FORM

APPENDIX C –
AIR EMISSIONS SUPPORTING CALCULATIONS

APPENDIX D –
LAER/BACT SUPPORTING DATA

ATTACHMENT D-A
COMBUSTION TURBINE

ATTACHMENT D-B
AUXILIARY BOILER

ATTACHMENT D-C
DEW POINT HEATER

ATTACHMENT D-D
EMERGENCY GENERATOR

ATTACHMENT D-E
FIRE WATER PUMP

ATTACHMENT D-F
NATURAL GAS PIPING COMPONENTS

ATTACHMENT D-G
CIRCUIT BREAKERS

ATTACHMENT D-H
STORAGE TANKS

APPENDIX E –
VENDOR INFORMATION

ATTACHMENT E-1
AUXILIARY BOILER

ATTACHMENT E-2
DEW POINT HEATER

ATTACHMENT E-3
EMERGENCY GENERATOR

ATTACHMENT E-4
FIRE WATER PUMP

APPENDIX F –
AIR QUALITY MODELING INFORMATION

APPENDIX G –
ACID RAIN AND CSAPR APPLICATION FORMS

APPENDIX H –
FUGITIVE DUST PREVENTION AND CONTROL PLAN

APPENDIX I –
STATE NOTIFICATIONS